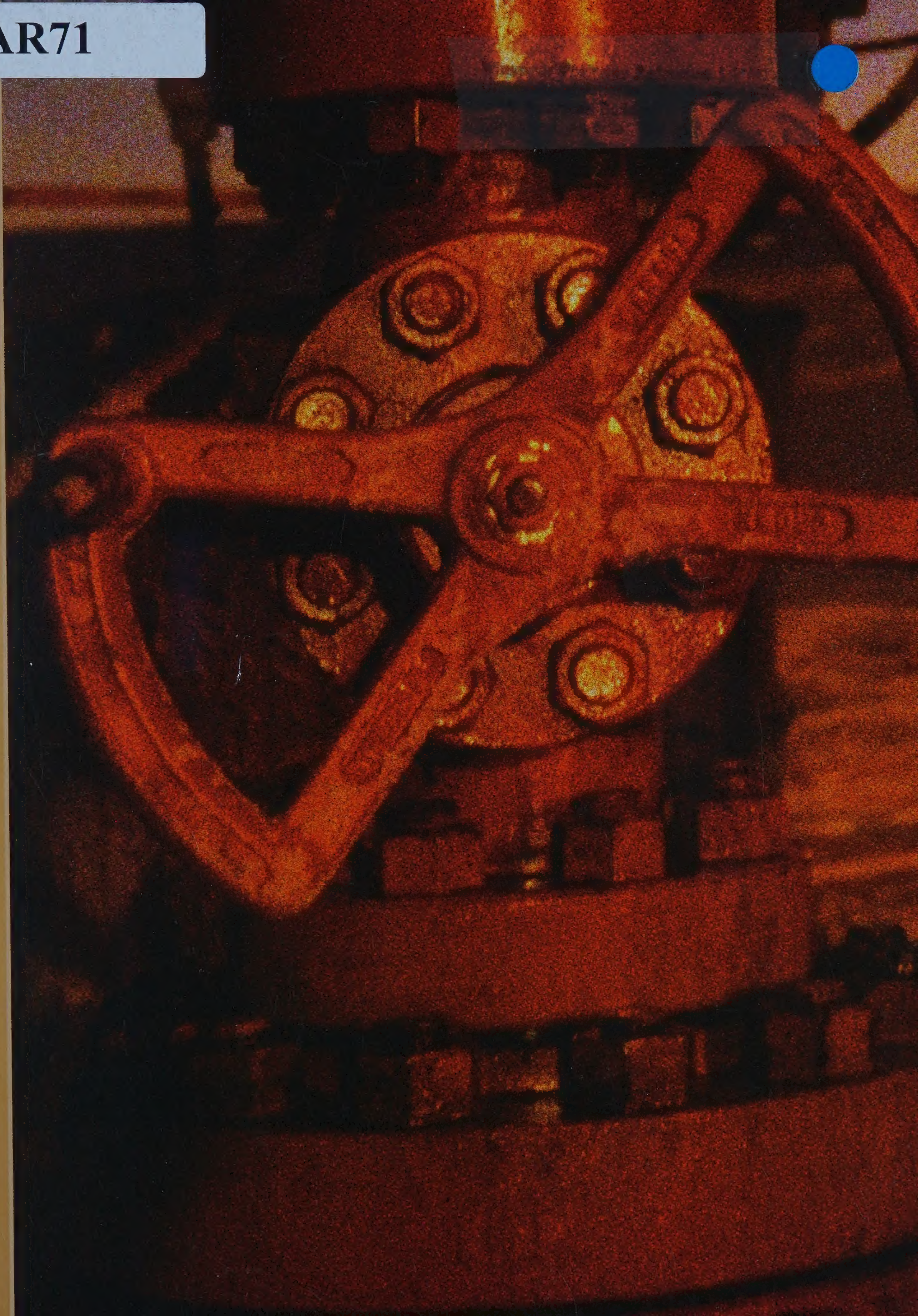
Crispin Energy Inc. 2003 Annual R



Corporate Profile

Crispin Energy Inc. ("Crispin") is an emerging oil and gas exploration and development company listed on the TSX Venture Exchange (trading under the symbol "CEY"), and has received conditional approval to list on the Toronto Stock Exchange (TSX).

The Company's goal is to increase shareholder value with a balanced combination of development and exploration drilling, supported by complementary acquisitions.

ANNUAL GENERAL MEETING

Shareholders are cordially invited to attend the Corporation's Annual General Meeting, which will be held at the Petroleum Club (Viking Room), located at 319 – 5th Avenue S.W., Calgary, Alberta at 10:00 a.m., Monday, May 10, 2004. Shareholders are encouraged to complete and return the enclosed proxy form to Valiant Corporate Trust Company's Calgary office if you are unable to attend the Annual General Meeting.

Growth for an emerging junior oil & gas company can be achieved by two methods; organic growth and/or acquisition.

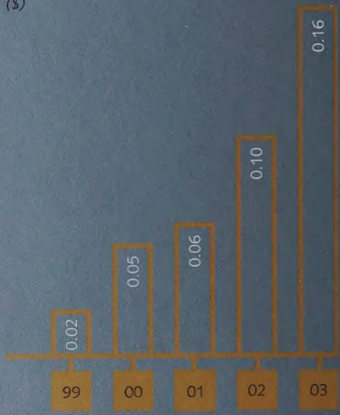
To sustain growth in today's market, a company must have a significant effort focused on organic growth and cannot rely upon acquisition opportunities which are limited and expensive.

Regardless of which method is used, an emerging junior must be **patient, disciplined & focused.**

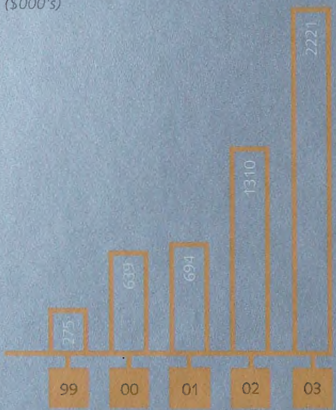
Crispin

Cash flow
($000's)

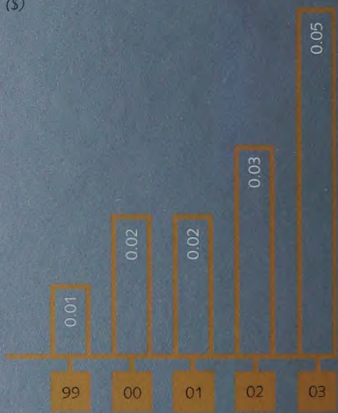
Cash flow per share
($)



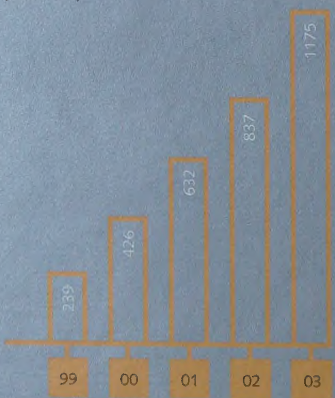
Net earnings
($000's)



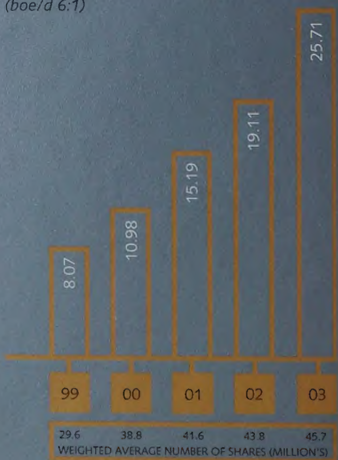
Net earnings per share (basic)
($)



Production
(boe/d 6:1)



Production /million shares (basic)
(boe/d 6:1)



Highlights

- Production volumes increased by 40%
- Cash flow increased by 64%
- Net earnings increased 70%

($ thousands, except per share amounts)	2003	2002	2001	2000	1999
FINANCIAL					
Petroleum and natural gas sales	**14,858**	9,891	6,053	4,075	1,925
Funds from operations	**7,256**	4,413	2,668	1,951	593
Net earnings	**2,221**	1,310	694	639	275
Capital expenditures	**23,386**	2,874	7,608	3,248	2,250
Net debt	**7,947**	3,997	6,228	1,451	883
Shareholders' equity	**23,624**	8,667	6,875	6,018	4,067
Funds from operations per share *(basic)*	**0.16**	0.10	0.06	0.05	0.02
Earnings per share *(basic)*	**0.05**	0.03	0.02	0.02	0.01
OPERATIONS					
Natural gas *(mcf/d)*	**818**	640	496	270	156
Light oil and NGL's *(bbls/d)*	**775**	520	323	154	78
Heavy oil *(bbls/d)*	**263**	210	226	227	135
Average daily boe's @ 6:1	**1,175**	837	632	426	239

Drawing **Crispin** →

President's Message

Crispin Energy Inc. is an emerging junior oil and gas producer that takes an exploitation style approach to growth. The Company looks to achieve cost effective growth in a balanced fashion: growth is achieved by identifying, exploiting, and drilling natural gas and light oil projects; through complementary acquisitions to existing project areas; and using a patient approach to development of new project areas for growth.

Prevailing industry conditions

There are three key types of companies that play significant roles in the Canadian oil and gas production industry: super independents, energy trusts, and juniors. In the last two years, the performance of all three has been driven to a large degree by the continued strengthening of oil and gas commodity prices. Increasing world demand and the slide in US currency has lifted oil pricing, while natural gas pricing has continued to strengthen because of North American supply deterioration. As a result, all three participants in this sector have experienced high levels of cash flow which provides ample capital for re-investment and/or return to shareholders.

Super independents (250,000 + boe/d) have continued to exploit and consolidate the positions they established in Western Canada in the 1990's. Due to high cash flows, the super independents have had a great reluctance to divest of assets that are not a long-term fit for their portfolio. For energy trusts (10,000 to 75,000 boe/d), the equation has been relatively simple: equity in, acquire, and cash distributions out. Similar to the super independents, there is little interest in divesting properties given favorable cash flow. For emerging junior oil and gas companies (1,000 - 10,000 boe/d), this reluctance to divest by the super independents and trusts has made for a limited and expensive acquisition market.

Growing Crispin

Growing a junior oil and gas company under the prevailing conditions can be a rewarding proposition for all stakeholders provided that patience, discipline, and focus are maintained. An emerging junior must be prepared to have a continuous effort focused on organic growth under these conditions. Crispin has continued growth through the drill bit while maintaining balance sheet leverage for larger acquisitions if available at a reasonable cost. The Company continues to identify, exploit, and drill natural gas and light oil projects focused in our Stettler project area while patiently pursuing assets with significant upside potential.

Crispin will continue to be focused on organic growth, while being patient for the right acquisition opportunities to develop.

Crispin is unlikely to pursue high leverage exploratory plays in the near future, but will continue the balanced approach with exploitation, drilling and complementary acquisitions.

On a cautionary note, one key factor affecting value added growth that inevitably follows high commodity pricing is a rise in the cost of services. Crispin mitigates this whenever possible by drilling on a program basis and balancing operations throughout the year rather than concentrating on one particular season for operations.

Crispin 2003 highlights

Crispin achieved its 2003 strategic goals of growth in reserves and cash flow, and simultaneously developed a concentration of assets in the Stettler project area. Crispin increased cash flow by 64%, in 2003 versus 2002, to $7.26 million ($0.15 per share on a fully diluted basis), and increased earnings by 70% to $2.2 million ($0.05 per share fully diluted). In 2003, the year-end net debt to cash flow ratio was 1.1, including the closing of the December 31, 2003 swap of the Mann Lake heavy oil assets for light oil and natural gas interests in Stettler. In total, the Company invested $23.4 million in capital in 2003, which was split roughly 60% on exploration and development drilling and 40% on acquisitions.

Gilbert Laustsen Jung and Associates (GLJ) evaluated Crispin's reserves in accordance with the NI 51-101 reserve standards. Crispin's reserve additions and positive revisions resulted in a 1.5 mmboe increase in total proved and 2.3 mmboe increase in total proved plus probable reserves. Finding costs on a total proved basis were $12.04/boe and $8.60/boe on a proved plus probable basis excluding future development capital. Finding costs on a total proved basis were $12.77/boe and $9.02/boe on a proved plus probable basis including all future development capital. As a result of 2003 investment activities, the corporate reserve life index was increased from 4.9 to 6.1 years on a total proved basis, and from 6.1 to 8.5 years on a proved plus probable basis using annualized Q4 production rates.

On the production side of the equation, Crispin increased average daily production to 1,175 boe/d – a 40% increase over average production from 2002. At the same time, the Company operating expenses were reduced by 14% on a year over year basis. This trend should continue with the swapping at year-end 2003 of the high operating cost heavy oil properties for light oil and natural gas production. Crispin drilled a total of 14.7 net wells with an 80% cased hole success rate, and also shifted the overall production base from 90% oil with a significant heavy oil component to a balanced light oil and natural gas portfolio by year-end. The Company has also achieved an overall strategic focus with 80% of its current production now derived from the Stettler project area.

Crispin is well positioned to continue growing.

Crispin winter 2003/2004 update

Crispin has finished its winter program in the Stettler project area. The program saw a total of 11 gross (8.7 net) wells drilled with targets at a depth of 1,000 - 1,800 meters. The program spending was split approximately 70% to shallow gas targets and 30% on deeper Cretaceous zones. This program should yield 300 - 400 boe/d of on stream rate net to Crispin by early Q2. The Stettler area continues to yield consistent rate and reserve results and, accordingly, Crispin will undertake a Q2 and Q3 drilling program of 6 - 10 gross wells on both the recently acquired Mikwan properties and the Three Hills project.

Crispin's Q4, 2003 production averaged 1,366 boe/d, while company production was 1,500 boe/d prior to the tie-in of the Q1 program. The Company did experience a 110 boe/d volume reduction resulting from operational difficulties with a Keg River well during Q1. The Company has elected not to pursue an operationally aggressive approach to production recovery at this time due to seasonal access limitations at Sousa.

Crispin is projecting a 2004 average annual production rate of 1,750 - 1,825 boe/d, which represents 50-55% growth on an annualized basis. The financial outlook for the Company continues to be strong. Crispin projects 2004 cash flow between $11.5 - $12.5MM and year-end debt to cash flow ratio between 0.6 - 0.9 depending on commodity pricing. This balance sheet strength allows Crispin to continue focusing on the patient pursuit of assets with upside potential that fit the corporate strategy. Crispin has increased its capital budget by $4.0MM to $15.2MM to accommodate expanded Q2 and Q3 drilling in 2004, and to increase the land and seismic budget allocation.

Summary

Crispin is well positioned to continue growing. The balance sheet is strong and has the potential for acquisitions or expanded organic activity. Crispin and its stakeholders are poised to reap the rewards of the winter 2003/2004 drilling program as the Company continues to add to its inventory of opportunities for the future. Crispin has a cohesive high functioning staff with the dedication, skills, ownership interest and experience to continue the growth pattern they have established. On behalf of all shareholders, I extend thanks to our staff for their dedication and efforts.

MURRAY R. NUNNS
President & Chief Executive Officer

Operations Review

Project Areas

Stettler [illegible]

Three Hills Creek [illegible] [illegible] [illegible]

2003 Drilling total

	Total wells	Oil	Gas	D&A
Gross	24.0	7.0	14.0	3.0
Net	14.7	3.0	8.8	2.9

Operating cost

($/boe)	2002	2003	2004[1]
Operating cost	7.86	6.79	5.90[1]

(1) Estimated for 2004.

Stettler

- Crispin operated
- 75% average W.I.
- 1,100 boe/d – December 31, 2003

Stettler drilling

	Total wells	Oil	Gas	D&A
Gross	21.0	4.0	14.0	3.0
Net	12.0	0.3	8.8	2.9

Stettler area operations overview

The Stettler area is the key focus area for Crispin. The project area is located approximately 100 km north of Calgary and encompasses an area of approximately 60 x 60 km. The area is predominately farmland and provides good accessibility, allowing the Company to proceed with operations throughout the year. The Stettler project area consists of three elements:

- **Three Hills, a major farm-in on Cretaceous gas plays, which Crispin committed to in Q1 2003;**
- **Mikwan, consisting of natural gas and light oil assets acquired in a year-end swap with a major producer in exchange for Crispin's heavy oil assets;**
- **Ewing Lake and Lousana, oil pools providing production from long reserves life, Paleozoic reservoirs.**

In total, Stettler represents 80% of the Company's production. Production from the area is roughly two thirds natural gas and one third oil and natural gas liquids. In 2003, the Company spent $21MM in the Stettler area, which was approximately 90% of Crispin's total capital spending budget, and was split with 60% dedicated to drilling, and 40% to complimentary acquisitions including Mikwan.

Stettler drilling

The bulk of the drilling in Stettler was for natural gas targets in the 1,000 - 1,800 meter range. Typical targets have reserves of 0.6 - 1.0 bcf with initial deliverability in the 300 - 500 mcf/d range. The wells targeted bypassed pay and pool extensions, typically in marine sands. Drilling, completion and equiping costs are generally in the $400M - $600M range per well. Overall the company achieved a 75% cased hole success rate on the Stettler projects in 2003. One of the significant outcomes of the 2003 drilling program in addition to production growth was extending the Company Reserve Life Index from 4.9 to 6.1 years on a proven reserves basis and from 6.1 to 8.5 on a proven plus probable basis using annualized Q4 production rates.

Stettler

[illegible] Hills Creek

Crispin entered into Three Hills through a major farm-in during Q1 of 2003. The farm-in provides Crispin with access to 110,000 acres as well as proprietary seismic and gas facilities. Terms of the deal called for the drilling of an initial six well earning program which was followed up with a second phase of earning drilled in Q4 2003 and Q1 2004. At the end of the second phase, Crispin will have secured access to the property for drilling through to Q1 2005 on a single well rolling option basis. This farm-in has provided Crispin with a large base of operations with access to facilities and has allowed the Company to build up its acreage holdings in the area and to provide further focus to Company operations. By year-end 2003 the Company was producing approximately 250 boe/d on the lands, a total which is anticipated to increase significantly in 2004.

Overall, the area has yielded consistent results, particularly from the shallower targets. The Company continues to concentrate on addressing key facilities limitations with its industry partner to ensure optimization of operations in the area.

Mikwan

Mikwan was acquired in a swap with a major producer in which Crispin acquired mixed natural gas and light oil assets in exchange for the Mann Lake heavy oil assets and a cash consideration. The Mikwan properties are high working interest assets located immediately adjacent to the Three Hills farm-in property. These assets provide Crispin with natural gas upside from shallow targets similar to those being exploited on the Three Hills property. Crispin controls the field operations relating to this production with gas being processed through third party facilities. The properties are a natural fit for Crispin and should provide growth in 2004 with initial drilling undertaken in Q1 2004.

Ewing Lake/Lousana

Ewing Lake and Lousana both produce from the Nisku formation, a Paleozoic Carbonate reservoir that is associated with long life oil reserves. The primary focus of Crispin's efforts in Ewing Lake and Lousana have been to achieve production optimization from its existing pools in order to bring operating costs in line with corporate targets. In 2002, operating costs were $7.22/boe versus 2003 operating costs of $6.85/boe. These pools have provided Crispin with a solid production foundation and the entry point for expansion in Stettler. At year-end these properties were producing approximately 400 boe/d.

Outlook

Stettler is an opportune area for growth at this stage of Crispin's development. Stettler has seen significant activity in Q1 2004 with an eleven well program as well as two re-completions. There will be a continued focus on shallow Cretaceous gas targets and the testing of other Cretaceous concepts, along with an emphasis on improving operational efficiencies. The Company will continue to look for complementary deals in the Stettler project area.

Rainbow Lake

Crispin lands

The Sousa property is a secondary producing property for Crispin and accounts for approximately 20% of the Company's overall production. The area produces light oil from Devonian Keg River reefs. The wells are typically high deliverability but tend to be isolated features. All production is operated through a Crispin owned battery, where Crispin has reduced operating costs on a year over year basis to \$4.76 boe/d from \$7.01 boe/d. This was supported in part by the drilling of one discovery well adjacent to the existing production base. Crispin has identified other exploitation opportunities in the area, which could be undertaken in the winter of 2004/2005. The Company has delayed more aggressive expansion of this area due to the capital intensive nature of operations and the limited area access during the summer months. Crispin views this as a harvest area and does not anticipate that it will be a long-term exploration development focus area for the Company.

Reserves Discussion & Analysis

2003 Year-end summary of reserves

The Company's reserve evaluation was prepared by the independent engineering firm of GLJ in 2003 and 2002 in accordance with NI 51-101. Reserves for 2002 were prepared by GLJ using National Policy 2-B.

- Comparability of Reserve Information - the change to proved and probable reserve definitions implemented by NI 51-101 for the year ended December 31, 2003 may make reserve quantity and value comparisons to prior years difficult. The proved plus risked probable reserve presented in 2002 and prior years were considered to be a reasonable estimate of the reserves that would actually be recovered and are comparable to the proved plus probable reserves calculated under NI 51-101. For the 2003 presentation, where comparisons of the 2003 proved plus probable reserves are made with prior years, the comparison is to the proved plus risked probable reserves.
- Reserves are stated on a Company interest basis (i.e. before royalty burdens and including royalty interests received).
- "Boes" may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
- Totals may not add due to rounding.

Company interest reserves

(forecasted prices and costs)	Light & Medium Crude Oil	Natural Gas Liquids	Natural Gas	2003 Boe	2002 Boe
	(mbbl)	*(mbbl)*	*(mmcf)*	*(mboe)*	*(mboe)*
Proved producing	1,355	118	6,395	2,538	1,297
Proved developed non-producing	8	5	1,339	237	164
Proved undeveloped	78	17	1,110	280	83
Total proved	1,442	140	8,844	3,056	1,544
Probable	296	65	4,825	1,165	388
Proved plus probable	1,737	205	13,669	4,221	1,932

Net present value of reserves

		Discounted			
(forecasted prices and costs)	Undiscounted	5%	10%	15%	20%
	($m)	*($m)*	*($m)*	*($m)*	*($m)*
Proved producing	39,482	33,518	29,295	26,144	23,699
Proved developed non-producing	3,420	2,893	2,473	2,138	1,870
Proved undeveloped	3,289	2,747	2,324	1,987	1,715
Total proved	46,190	39,158	34,092	30,270	27,284
Probable	18,500	13,696	10,781	8,845	7,474
Proved plus probable	64,691	52,854	44,873	39,115	34,758

[illegible] type (forecast prices and costs)

Total proved *(forecasted prices and costs)*	Light & Medium Crude Oil *(mbbl)*	Heavy Oil *(mbbl)*	Natural Gas *(mmcf)*	Natural Gas Liquids *(mbbl)*	Total Boe *(mboe)*
January 1, 2003	995	272	1,449	35	1,544
Drilling extensions and discoveries	0	0	3,288	31	579
Improved recovery	0	0	0	0	0
Technical revisions	453	38	(28)	3	489
Acquisitions	282	0	4,471	77	1,104
Dispositions	(11)	(214)	(37)	0	(231)
Economic factors	0	0	0	0	0
Net additions	724	(176)	7,694	111	1,941
Production	(277)	(96)	(299)	(6)	(429)
January 1, 2004	1,442	0	8,844	140	3,056

Proved plus probable *(forecasted prices and costs)*	Light & Medium Crude Oil *(mbbl)*	Heavy Oil *(mbbl)*	Natural Gas *(mmcf)*	Natural Gas Liquids *(mbbl)*	Total Boe *(mboe)*
January 1, 2003	1,187	355	2,086	43	1,932
Drilling extensions and discoveries	0	0	4,354	63	788
Improved recovery	0	0	0	0	0
Technical revisions	513	38	430	(12)	610
Acquisitions	328	0	7,142	118	1,636
Dispositions	(13)	(297)	(44)	0	(317)
Economic factors	0	0	0	0	0
Net additions	828	(299)	11,882	169	2,717
Production	(277)	(96)	(299)	(6)	(429)
January 1, 2004	1,737	0	13,669	205	4,221

[illegible] acquisitions costs

The implementation of NI 51-101 requires that Finding Development and Acquisition (FD&A) costs and Finding and Development (F&D) costs be calculated using the Company's capital expenditures for the reporting period and including the independent reserve evaluation estimates of Future Development Costs (FDC) included in the engineering report.

FD&A and F&D costs are presented for the 2003 period. Due to the implementation of NI 51-101, calculation of two and three year F&D and FD&A costs would be misleading as reserve standards have changed.

The Company is presenting F&D and FD&A costs both before and after the inclusion of future development capital to illustrate the relative impact of FDC.

Total proved	Capital Expenditures ($m)	Net Reserve Additions (mboe)[3]	Cost ($/boe)[2]
FD&A before future development capital	23,386	1,941	12.04
FD&A after including future development capital	24,787	1,941	12.77
F&D before including future development capital	12,545	1,068	11.75
F&D after including future development capital	13,946	1,068	13.05
Net acquisition costs [1]	10,841	873	12.42

Proved plus probable	Capital Expenditures ($m)	Net Reserve Additions (mboe)[3]	Cost ($/boe)[2]
FD&A before future development capital	23,386	2,717	8.60
FD&A after including future development capital	24,518	2,717	9.02
F&D before including future development capital	12,545	1,398	8.97
F&D after including future development capital	13,677	1,398	9.78
Net acquisition costs [1]	10,841	1,319	8.21

Reconciliation of change in future development capital ($M)	Total Proved	Change	Proved Plus Probable	Change
2003	1,902		2,622	
		1,401		1,132
2002	501		1,490	

(1) Includes $1,410M capital relating to drilling, completions, and facilities on properties disposed in 2003.

(2) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year

(3) Net reserve additions include all revisions to prior years

Reserve life index

The Reserve Life Index (RLI) is provided for year end 2003 and year end 2002 as a comparison.

The RLI has been calculated using annualized fourth quarter production rates for the respective periods as opposed to full year production averages, the effect of which is to slightly shorten the presented RLI and better match production rates to reserves.

The RLI is calculated by dividing the Company's total reserve in boe's in a particular reserve category by the annualized production rate.

	2003 Annualized Q4 Production	2002 Annualized Q4 Production
Production *(mboe)*	499	316
Total proved reserves *(mboe)*	3,056	1,544
Total proved RLI *(years)*	6.1	4.9
Proved plus probable reserves *(mboe)*	4,221	1,932
Proved plus probable RLI *(years)*	8.5	6.1

The recycle ratio is a measure for evaluating the effectiveness of a Company's re-investment program. The ratio measures the efficiency of capital investment. It accomplishes this by comparing the field netback per barrel of oil equivalent to the year's reserve finding and development costs.

A ratio greater than 1.0 implies value creation. Crispin targets a ratio of 1.5 or greater to allow for the impact of variables such as commodity price, thereby ensuring value creation through all parts of the commodity price cycle.

The recycle ratios presented below are calculated using the all-in FD&A costs for 2002 and 2003.

	2003
Operating netback *($/boe)*	$ 20.39
Total proved FD&A[1] *($/boe)*	$ 12.77
Total proved recycle ratio	1.6
Proved plus probable FD&A[1] *($/boe)*	$ 9.02
Proved plus probable recycle ratio	2.3

(1) Includes future development capital.

The field netback for 2003 is adversely affected by the heavy oil component of the Company's production stream. Accordingly, the recycle ratios presented would be higher if the Company's FD+A (primarily related to gas drilling) were to be compared to gas and light oil netbacks.

Reserve replacement is a measure of the amount of the Company's current year production that has been replaced by new capital activity.

For 2003, the Company produced 429 mboe and added 1,941 mboe of new total proved reserves and 2,717 mboe of new proved plus probable reserves for reserve replacement ratios as presented below.

2003 production *(mboe)*	429
Total proved net reserve addition *(mboe)*[1]	1,941
Total proved reserve replacement ratio	4.5
Proved plus probable net reserve addition *(mboe)*[1]	2,717
Proved plus probable reserve replacement ratio	6.3

(1) Net reserve additions include all revisions to prior periods.

Management's Discussion and Analysis

The Management Discussion and Analysis (MD&A) that follows is intended to supplement the financial statements and the accompanying notes that are contained in this annual report. The information provided in this MD&A is given as of March 8, 2004.

In this MD&A, the calculation of boe is based on the conversion rate of six thousand cubic feet of natural gas for one barrel of crude oil (6:1), unless otherwise stated. This conversion conforms to National Instrument 51-101 – Standards for Oil and Gas Activities of the Canadian Securities Administrators (NI 51-101). Calculations of boe for the previously reported years have been adjusted from a 10:1 basis to the current 6:1 standard. Boe's may be misleading particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All comparisons refer to the period ended December 31, 2003 compared with the period ended December 31, 2002, unless otherwise indicated. All production volumes quoted in this MD&A refer to our working interest share, unless otherwise indicated. Estimates of future operating and financial performance are based on information currently available.

This MD&A contains certain terms such as "funds from operations", "cash flow per share", "cash flow", "netback analysis" and "netbacks per boe". These measurements should not be considered an alternative to, or more meaningful than, net earnings or cash flow from operating activities, determined in accordance with Canadian generally accepted accounting principles (GAAP), as indicators of our financial performance or liquidity. Our funds from operations, netback analysis and netbacks per boe may not be comparable to those reported by other companies, and are included as supplemental information only. The reconciliation between net earnings and cash flow from operations can be found in our consolidated statements of cash flows contained in our audited financial statements. Further, when presenting funds from operations per share, we have calculated per share amounts using the weighted average shares outstanding in a manner that is consistent with our calculation of earnings per share.

When used in this MD&A, the following abbreviations have the meanings set forth below:

Oil and Natural Gas

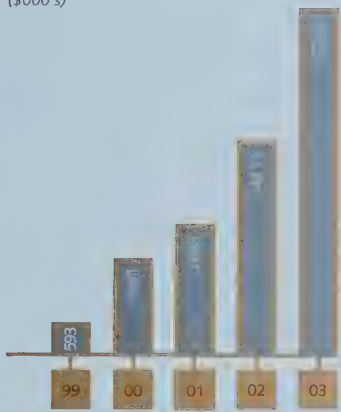
bbl	barrel of oil
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
bopd	barrels of oil per day

Natural Gas

mcf	thousand cubic feet
mcf/d	thousand cubic feet per day

This MD&A and all of our other public filings can be found on the SEDAR site located at www.sedar.com

Cash flow
($000's)



Net earnings
($000's)

Overview

The following table summarizes field and operating netbacks, funds generated from operations and net earnings for the three months and twelve months ended December 31, 2003 and December 31, 2002

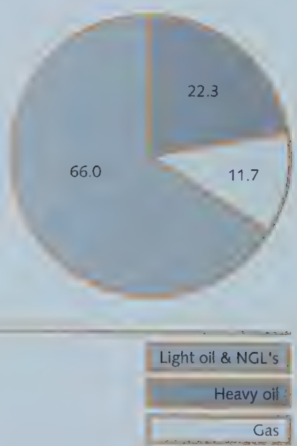
	Three months ended December 31			Twelve months ended December 31		
($000's - unaudited)	**2003**	2002	%	**2003**	2002	%
Petroleum and natural gas sales	**4,076**	2,761	48	**15,255**	10,001	53
Royalties, net of ARTC	**(812)**	(610)	33	**(3,206)**	(1,939)	65
Operating expenses	**(871)**	(616)	41	**(2,910)**	(2,403)	21
Field netback	**2,393**	1,535	56	**9,139**	5,659	62
Hedging adjustments	**(41)**	(41)	–	**(397)**	(110)	261
Operating netback	**2,352**	1,494	57	**8,742**	5,549	58
Other income	**13**	16	(19)	**33**	53	(37)
General and administrative	**(315)**	(216)	45	**(1,106)**	(822)	35
Interest	**(93)**	(59)	59	**(346)**	(299)	15
Capital taxes	**(41)**	(9)	355	**(48)**	(9)	438
Other expense	**–**	–	–	**(19)**	(59)	(68)
Funds from operations	**1,916**	1,226	56	**7,256**	4,413	64
Depletion, depreciation and amortization	**(1,396)**	(720)	94	**(4,125)**	(2,484)	66
Stock based compensation	**(106)**	–	–	**(106)**	–	–
Future income taxes	**(233)**	(361)	(35)	**(804)**	(742)	8
Net earnings, before extraordinary item	**181**	145	25	**2,221**	1,187	87
Extraordinary gain	**–**	122	–	**–**	122	–
Net earnings	**181**	267	(32)	**2,221**	1,309	70

Netbacks $/boe

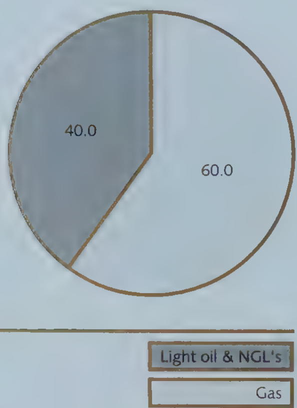
The following table summarizes field and operating netbacks, funds generated from operations and net earnings per boe for the three months and years ended December 31, 2003 and December 31, 2002.

	Three months ended December 31			Twelve months ended December 31		
(unaudited)	**2003**	2002	%	**2003**	2002	%
Production revenue	**$ 32.47**	$ 34.63	(6)	**$ 35.59**	$ 32.72	9
Royalties, net of ARTC	**(6.47)**	(7.65)	(15)	**(7.48)**	(6.34)	18
Production expenses	**(6.94)**	(7.73)	(10)	**(6.79)**	(7.86)	(14)
Field netback	**19.06**	19.25	(1)	**21.32**	18.52	15
Hedging losses	**(0.33)**	(0.51)	(36)	**(0.93)**	(0.36)	158
Operating netback	**18.73**	18.74	–	**20.39**	18.16	12
Other income	**0.11**	0.20	(48)	**0.08**	0.17	(55)
General and administrative	**(2.51)**	(2.71)	(8)	**(2.58)**	(2.69)	(4)
Interest and capital taxes	**(1.07)**	(0.85)	26	**(0.92)**	(1.01)	(9)
Other expense	**–**	–	–	**(0.04)**	(0.19)	(79)
Funds from operations	**15.26**	15.38	(1)	**16.93**	14.44	17
Depletions, depreciation and amortization	**(11.13)**	(9.03)	23	**(9.62)**	(8.13)	18
Stock based compensation	**(0.84)**	–	–	**(0.25)**	–	–
Future income taxes	**(1.86)**	(4.53)	(59)	**(1.88)**	(2.43)	(23)
Net earnings *(before extraordinary item)*	**$ 1.43**	$ 1.82	(21)	**$ 5.18**	$ 3.88	34

2003 Production mix
(%) Year average



2004 Production mix
(%) Forecasted year average



Production

Daily production – boe

(unaudited)	Three months ended December 31 **2003**	2002	%	Twelve months ended December 31 **2003**	2002	%
Crude oil – light	**833**	550	51	**775**	520	49
Crude oil - heavy	**254**	245	4	**263**	210	25
Total crude oil	**1,087**	795	37	**1,038**	730	42
Natural gas *(mcf/d)*	**1,675**	429	290	**818**	640	28
Total daily production *(boe @ 6:1)*	**1,366**	866	58	**1,175**	837	40

For the fourth quarter of 2003, our average daily production increased by 58% to 1,366 boe/d from the 866 boe/d recorded during the fourth quarter of 2002. Average daily production of crude oil and liquids increased 37% to 1,087 bopd, primarily from light oil additions at the Sousa, Ewing Lake, and Lousana properties. Daily production of natural gas during the fourth quarter of 2003 was up by 290% to 1,675 mcf/d, reflecting the addition of natural gas volumes from the Three Hills gas exploration program undertaken in the second half of 2003. The fourth quarter commodity mix was made up of 61% light crude oil (64% in the fourth quarter of 2002), 19% heavy crude oil (28% in the fourth quarter of 2002) and 20% natural gas (8% in the fourth quarter of 2002).

For the year ended December 31, 2003, production averaged 1,175 boe/d, up 40% from 2002. During 2003, we increased our daily average crude oil production by 42% to 1,038 bopd from the 730 bopd recorded for 2002. We realized significant increases in daily volumes at Rainbow (Sousa) and Stettler (Ewing Lake and Lousana). These increases are the result of drilling and work-over operations conducted on those properties during 2003. Daily production of natural gas averaged 818 mcf/d during 2003, up 28% from the 640 mcf/d recorded in 2002. The increases in our daily average production rate of natural gas during 2003 are the result of the natural gas exploration program we undertook on the Stettler (Three Hills Creek) property during the second half of 2003. The year-to-date commodity mix is made up of 66% light crude oil (62% in 2002), 22% heavy crude oil (25% in 2002) and 12% natural gas (13% in 2002).

At the end of the fourth quarter of 2003, we swapped all of our working interests in the Bonnyville area heavy oil leases and production to a third party as part of a larger transaction. In exchange for our heavy oil interests and cash, we received approximately 370 boe/d of production, consisting of 1.75 mcf/d of natural gas and 80 bopd of liquids and light crude oil, and an inventory of undeveloped lands located in our existing Stettler core area. As a result of this property swap, our 2004 production will now entirely consist of light crude oil and natural gas.

Daily production – by area

Crude oil *(bopd)*	Three months ended December 31 2003	2002	%	Twelve months ended December 31 2003	2002	%
Rainbow (Sousa)	**394**	302	30	**399**	294	36
Mann Lake – Bonnyville (heavy)	**254**	245	4	**263**	210	25
Stettler (Lousana)	**226**	115	97	**174**	114	53
Stettler (Ewing Lake)	**154**	91	69	**153**	57	168
Other	**59**	42	40	**49**	55	(11)
Total crude oil	**1,087**	795	37	**1,038**	730	42
Natural gas *(mcf/d)*						
Stettler (Three Hills Creek)	**1,111**	–	–	**413**	–	–
Sylvan Lake	**121**	170	(29)	**131**	168	(22)
Stettler (Lousana)	**155**	98	58	**105**	84	25
Rainbow (Sousa)	**–**	4	(100)	**–**	221	(100)
Other	**288**	157	83	**169**	167	1
Total natural gas *(mcf/d)*	**1,675**	429	290	**818**	640	28
Total daily production *(boe @ 6:1)*	**1,366**	866	58	**1,175**	837	40

Production revenue

($000's)	Three months ended December 31 2003	2002	%	Twelve months ended December 31 2003	2002	%
Crude oil – light	**2,772**	2,059	35	**11,207**	7,189	56
Crude oil – heavy	**433**	546	(21)	**2,229**	1,962	14
Crude oil – hedging	**(41)**	(41)	–	**(397)**	(110)	261
Total crude oil	**3,164**	2,564	23	**13,039**	9,041	44
Natural gas	**871**	157	455	**1,819**	849	114
Total production revenue	**4,035**	2,721	48	**14,858**	9,890	50

Our gross crude oil and natural gas revenues for the fourth quarter of 2003 amounted to $4,034,926, up 48% when compared to the $2,716,387 recorded for the same period in 2002. Increased average production volumes during the fourth quarter of 2003 (up 58% over the fourth quarter of 2002) have primarily driven the increases we recorded in gross revenues. These increases have been tempered by an 11% decrease in the average Canadian to US dollar exchange rate to 1.40:1 for 2003, compared to an average US dollar exchange rate of 1.57:1 for 2002. The change in the Canadian to US dollar exchange rate occurred primarily during the second half of 2003.

Our gross crude oil and natural gas revenues increased by 50% in 2003 to $14,858,036 from the $9,890,913 recorded in 2002. This increase in our production revenues for the year is attributable to a combination of a 40% increase in production volumes, to an average of 1,175 boe/d, and a 7% increase in the average Canadian dollar selling price per boe for 2003.

($/boe)	Three months ended December 31			Twelve months ended December 31		
	2003	2002	%	**2003**	2002	%
Crude oil – light	**36.15**	40.66	(11)	**39.59**	37.84	5
Crude oil – heavy	**18.53**	24.23	(24)	**23.26**	25.58	(9)
Crude oil – hedging	**(0.33)**	(0.51)	(35)	**(0.93)**	(0.36)	158
Total crude oil	**31.71**	35.09	(10)	**34.53**	33.95	2
Natural gas *(mcf)*	**5.70**	3.98	43	**6.09**	3.64	67
Total production revenue *(boe @ 6:1)*	**32.15**	34.12	(6)	**34.66**	32.36	7

Sales dollars for the fourth quarter were made up of 68% light oil at an average of $36.15/bbl (75% averaging $40.66/bbl in the fourth quarter of 2002), 11% heavy oil at an average of $18.53/bbl (20% averaging $24.23/bbl in the fourth quarter of 2002) and 21% natural gas at an average $5.70/mcf (5% averaging $3.98/mcf in the fourth quarter of 2002). Our blended average commodity price, net of hedging adjustments, for the fourth quarter of 2003 was down 6% to $32.15/boe as compared to $34.12/boe in the fourth quarter of 2002.

Sales dollars for the year ended December 31, 2003 were made up of 73% light oil at an average of $39.59/bbl (72% averaging $37.84/bbl in 2002), 15% heavy oil at an average of $23.26/bbl (20% averaging $25.58/bbl in 2002) and 12% natural gas at an average $6.09/mcf (8% averaging $3.64/mcf in 2002). Our blended average field commodity price, net of hedging adjustments, for 2003 was up 7% to $34.66/boe as compared to $32.36/boe in 2002.

Given the disposal of our heavy oil properties at the end of 2003, we expect to immediately realize an increase in gross oil and natural gas revenues. The revenues realized, on a per boe basis, from the newly acquired light crude oil and natural gas production is currently nearly twice the revenue per barrel of that generated from a barrel of heavy crude oil.

Risk management

In aggregate, our hedging adjustments have resulted in the realization of a $397,345 ($0.93/boe) revenue adjustment during 2003 compared to $109,973 ($0.36/boe) during 2002. The majority of our hedging adjustments during 2003 originated in the first quarter of 2003. Hedging adjustments for the fourth quarter of 2003 amounted to $41,269 ($0.33/boe) compared to $40,846 ($0.52/boe) for the fourth quarter of 2002.

During the fourth quarter of 2003, we entered into two new crude oil collars, each for 400 bopd. The first crude oil collar establishes a floor price of US $25.00 and a ceiling price of US $32.50, and runs from January 1, 2004 to March 31, 2004. The second crude oil collar establishes a floor price of US $26.00 and a ceiling price of US $32.00, and runs from April 1, 2004 to June 30, 2004. Subsequent to the end of 2003, we entered into two natural gas collars, each for 1,000 gigajoules per day and both running from April 1, 2004 to October 31, 2004. The first natural gas collar establishes a floor price of CA $5.00 and a ceiling price of CA $7.00 per gigajoule. The second natural gas collar establishes a floor price of CA $5.00 and a ceiling price of CA $6.75 per gigajoule.

We include our hedging gains and losses as adjustments to gross petroleum and natural gas sales and use hedging as a tool to help underpin our expected near term capital expenditures (by ensuring minimum cash flows) and to maintain the debt to cash flow ratio within our stated objectives. We also maintain a corporate policy regarding our hedging activities which limits commodity hedging activities to a maximum of 50% of forward production and the time period for commodity hedging to not more than 18 months. Hedging activities outside these limits, or that involve the fixing prices or currency exchange rates, require the approval of our Board of Directors.

Royalties

	Three months ended December 31			Twelve months ended December 31		
($000's)	**2003**	2002	%	**2003**	2002	%
Crude oil – light	**647**	591	9	**2,923**	1,716	70
Crude oil – heavy	**4**	5	(20)	**21**	19	10
Total crude oil	**651**	596	9	**2,944**	1,735	70
Natural gas	**139**	17	717	**266**	218	22
ARTC	**22**	(4)	(450)	**(4)**	(14)	(71)
Royalties *(net)*	**812**	609	33	**3,206**	1,939	65

For the fourth quarter of 2003, our royalty expense increased 33% to $811,952 from $609,673 in the fourth quarter of 2002. This increase in our royalty expense is the combined result of a 48% increase in production revenues and a 58% increase in production volumes during the fourth quarter of 2003, when compared to the fourth quarter of 2002.

Our royalty expense, net of Alberta Royalty Tax Credit (ARTC), increased 65% to $3,206,161 for the year ended December 31, 2003 from $1,938,968 during the same period in 2002. This increase in royalty expense is the combined result of a 50% increase in our production revenues and a 40% increase in our production volumes during 2003. Production additions reflected since the first quarter of 2003 were made on properties with a royalty rate higher than the corporate average, while production additions made during the third and fourth quarters of 2003 were on properties with royalty rates at or below the corporate average.

	Three months ended December 31			Twelve months ended December 31		
($/boe)	**2003**	2002	%	**2003**	2002	%
Crude oil – light	**8.44**	11.68	(28)	**10.33**	9.03	14
Crude oil – heavy	**0.16**	0.23	(30)	**0.21**	0.24	(13)
Total crude oil	**6.51**	8.15	(20)	**7.77**	6.50	20
Natural gas *($/mcf)*	**0.91**	0.44	107	**0.89**	0.94	(5)
ARTC	**0.17**	(0.05)	340	**(0.01)**	(0.05)	(80)
Total royalties *(boe @ 6:1)*	**6.47**	7.65	(15)	**7.48**	6.34	18

During the fourth quarter of 2003, our royalty cost per boe decreased 15% to $6.47/boe from the $7.65/boe recorded in 2002. This decrease reflects both a 6% decline in overall revenue/boe and the addition of lower royalty rate natural gas production in the Stettler area during the fourth quarter of 2003.

Our total 2003 royalty cost per boe increased 18% to average $7.48/boe compared to $6.34/boe in 2002. This increase is the combined result of a 7% increase in our average net boe selling price and a 20% increase in our average crude oil royalty rate, reflecting additions of higher royalty rate light crude oil production during the year.

Our overall effective royalty rate averaged 21% for 2003 as compared to 19% for the same period in 2002. Our average royalty rate on crude oil was 22% (compared to 19% in 2002). This increase in our average crude oil royalty rate is the result of crude oil production additions coming from higher royalty rate lands. The natural gas royalty rate averaged 15% (compared to 26% in 2002). This decrease in our average natural gas royalty rate is the result of our suspension of the higher royalty rate natural gas at Sousa and the addition of lower royalty rate natural gas production in the Stettler area.

Operating expense

	Three months ended December 31			Twelve months ended December 31		
($000's)	**2003**	2002	%	**2003**	2002	%
Crude oil – light	**473**	358	32	**1,664**	1,416	18
Crude oil – heavy	**187**	139	35	**775**	512	51
Total crude oil	**660**	497	33	**2,439**	1,928	26
Natural gas	**211**	119	77	**470**	475	(1)
Total operating expenses	**871**	616	41	**2,909**	2,403	21

Our total operating expenses for the fourth quarter of 2003 were up 41% to $871,234 from the $616,526 recorded during the fourth quarter of 2002. This increase in total operating expenses reflects the combined effect of increased levels of production, costs savings realized on our light oil and natural gas production streams and higher operating expenses associated with the Mann Lake heavy oil production.

Our total operating expenses were up 21% to $2,909,474 for 2003 from the $2,402,850 recorded in 2002. This increase in our operating expenses primarily reflects our production growth during 2003, as our per boe operating expenses have declined during this period.

	Three months ended December 31			Twelve months ended December 31		
($/boe)	**2003**	2002	%	**2003**	2002	%
Crude oil – light	**6.17**	7.07	(13)	**5.88**	7.45	(21)
Crude oil – heavy	**8.00**	6.19	29	**8.08**	6.67	21
Total crude oil	**6.60**	6.80	(3)	**6.44**	7.23	(11)
Natural gas *($/mcf)*	**1.38**	3.02	(54)	**1.58**	2.03	(22)
Total operating expenses *(boe @ 6:1)*	**6.94**	7.73	(10)	**6.79**	7.86	(14)

Our light oil operating expenses for the fourth quarter of 2003 averaged $6.17/bbl, down 13% compared to $7.07/bbl for the fourth quarter of 2002. The reduction in these costs is largely due to increased volumes at each

of our major light oil properties. Heavy oil operating expenses averaged $8.00/bbl during the fourth quarter of 2003 (compared to $6.19/bbl during the fourth quarter of 2002). The fourth quarter increase of 29% in our heavy oil operating costs per boe reflect the increased costs of utilities and heavy oil well services. The blended average operating expense per boe for the fourth quarter of 2003 averaged $6.94/boe, down 10% from the $7.73/boe recorded in the fourth quarter of 2002.

On a boe basis, our 2003 average operating expenses decreased by 14% to $6.79/boe from $7.86/boe in 2002. Our 2003 heavy oil operating expenses increased 21% to $8.08/bbl, compared to $6.67/bbl for 2002, while the year-to-date light oil operating expenses were down 21% to $5.88/bbl for 2003, compared to $7.45/bbl for 2002. This decrease in our overall operating expense per bbl is attributable to both volume additions on each of our core properties and the installation of new treating and shipping facilities at Ewing Lake late during the second quarter of 2003.

Our operating expenses associated with natural gas averaged $1.58/mcf during 2003, compared to $2.03/mcf in 2002. We expect to further reduce our per mcf operating expense for natural gas in 2004 as additional volumes of natural gas are brought on stream from the ongoing Stettler area natural gas exploration program during the early part of 2004.

The impact of the property swap of our heavy oil assets for a lighter product stream late in the fourth quarter of 2003 should have the effect of further reducing our 2004 per unit operating expenses, as the production received in the property swap costs approximately $2.00/boe less to produce than the heavy oil operating expenses per barrel averaged during 2003. Our continued focus on natural gas drilling in the capital program should further improve our average operating expense per boe.

Field netback by product

	Oils and liquids							
	Conventional		Heavy		Natural gas		2003 Total	
2003 Production	**775 bbls/day**		**263 bbls/day**		**818 mcf/day**		**1,175 boe/day**	
	($000's)	*($/bbl)*	*($000's)*	*($/bbl)*	*($000's)*	*($/mcf)*	*($000's)*	*($/boe)*
Production revenue	**11,207**	**39.59**	**2,230**	**23.26**	**1,819**	**6.09**	**15,256**	**35.59**
Royalties, net ARTC	**(2,919)**	**(10.32)**	**(21)**	**(0.21)**	**(266)**	**(0.89)**	**(3,206)**	**(7.48)**
Operating expense	**(1,664)**	**(5.88)**	**(774)**	**(8.08)**	**(471)**	**(1.58)**	**(2,909)**	**(6.79)**
Field netback	**6,624**	**23.39**	**1,435**	**14.97**	**1,082**	**3.62**	**9,141**	**21.32**

Excludes hedging adjustments

	Oils and liquids							
	Conventional		Heavy		Natural gas		2002 Total	
2002 Production	520bbls/day		210 bbls/day		642 mcf/day		837 boe/day	
	($000's)	*($/bbl)*	*($000's)*	*($/bbl)*	*($000's)*	*($/mcf)*	*($000's)*	*($/boe)*
Production revenue	7,190	37.84	1,962	25.58	849	3.64	10,001	32.72
Royalties, net ARTC	(1,702)	(8.98)	(19)	(0.24)	(218)	(0.94)	(1,939)	(6.34)
Operating expense	(1,416)	(7.45)	(512)	(6.67)	(475)	(2.03)	(2,403)	(7.86)
Field netback	4,072	21.41	1,431	18.67	156	0.67	5,659	18.52

Excludes hedging adjustments

General and administrative expense

($000's)	Three months ended December 31			Twelve months ended December 31		
	2003	2002	%	**2003**	2002	%
Gross G&A expense	**551.0**	438.9	25	**1,830.6**	1,311.4	40
Overhead recoveries	**(109.2)**	(85.3)	28	**(343.4)**	(146.7)	134
Capitalized G&A expense	**(127.4)**	(137.3)	(7)	**(380.9)**	(343.3)	11
General and administrative expenses	**314.4**	216.3	45	**1,106.3**	821.4	35

Our general and administrative (G&A) expenses, net of recoveries and capitalized costs, for the fourth quarter of 2003 amounted to $314,467 compared to $216,325 for the fourth quarter of 2002, a 45% increase. Our G&A expenses, net of recoveries and capitalized costs, increased 35% to $1,106,314 for 2003 from the $821,437 recorded for 2002.

The increase in both our fourth quarter and annual G&A expenses is directly related to our higher levels of activity during the year and to the one-time costs we incurred during the fourth quarter of 2003 in establishing an internal partnership and preparing to list on the Toronto Stock Exchange (TSX).

($/boe)	Three months ended December 31			Twelve months ended December 31		
	2003	2002	%	**2003**	2002	%
Gross G&A expense	**4.39**	5.61	(22)	**4.27**	4.29	–
Overhead recoveries	**(0.87)**	(1.07)	(19)	**(0.80)**	(0.48)	67
Capitalized G&A expense	**(1.01)**	(1.72)	(41)	**(0.89)**	(1.12)	(20)
G&A expense *(boe @ 6:1)*	**2.51**	2.71	(7)	**2.58**	2.69	(4)

On a dollar per boe of production basis, our G&A expenses for the fourth quarter of 2003 were down 7% to $2.51/boe (compared to $2.76/boe in the fourth quarter of 2002). Our G&A expenses decreased by 4% during 2003 to $2.58/boe from $2.69/boe in 2002. Our per boe G&A expenses will continue to reduce through both increased levels of capital activity (G&A recoveries) and increased levels of production. Consequently, we expect our G&A expenses, on a boe basis, to decrease during 2004. We believe we can add 500 to 1,000 boe/d to our production with only limited staffing additions.

Interest expense

Our interest expense for the fourth quarter of 2003 amounted to $93,221 ($0.74/boe) compared to $58,782 ($0.75/boe) for the fourth quarter of 2002. Interest expense increased to $345,597 ($0.81/boe) for 2003 from $299,371 ($0.98/boe) in 2002. Our increased average borrowings, lower average interest rates and higher average production levels during 2003 contributed to both the increase in our interest costs and the decline in our interest costs per boe.

Income and capital taxes

Our provision for future income taxes was $233,007 for the three months ended December 31, 2003 and $804,447 for 2003, after adjustment for changes in both federal and provincial tax rates. We paid $48,430 in large corporation capital taxes for 2003 and $9,000 for 2002.

Included in our 2003 future income tax provision is a benefit of $183,661 that relates to enacted changes to the federal income tax rate and deductions for resource income. These tax changes will reduce the rate on resource income by 7%, provide for the deduction of crown royalties and eliminate the resource allowance, and will be phased in over a five year period. Additionally, we recorded a benefit of $41,688, which relates to a 0.5% reduction in the Alberta income tax rate.

Depletion, depreciation and amortization

	Three months ended December 31			Twelve months ended December 31		
($000's)	**2003**	2002	%	**2003**	2002	%
Depletion, P&NG assets	**1,241.7**	661.9	88	**3,846.2**	2,365.9	63
Depreciation – other	**9.1**	5.0	82	**32.9**	14.2	132
Provision for site restoration	**145.6**	53.5	172	**245.6**	103.3	138
	1,396.3	720.4	94	**4,124.7**	2,483.4	66

Our depletion, depreciation and amortization charges for 2003 increased to $4,124,724 from $2,483,495 for 2002. On a boe basis, depletion, depreciation and amortization was $9.62/boe in 2003 compared to $8.13/boe for 2002, an increase of 18%. This increase in our depletion, depreciation and amortization rate results from a combination of increasing service industry costs, increased infrastructure, safety, environmental and facility spending and increased future site provisions. This is a trend that should appear industry wide, because of the above noted factors and given the anticipated industry effects of the implementation of NI 51-101 governing reserve calculations.

	Three months ended December 31			Twelve months ended December 31		
($/boe)	**2003**	2002	%	**2003**	2002	%
Depletion, P&NG assets	**9.90**	8.30	19	**8.97**	7.61	18
Depreciation – other	**0.07**	0.06	16	**0.08**	0.18	(56)
Provision for site restoration	**1.16**	0.67	73	**0.57**	0.34	68
DD&A expense *(boe @ 6:1)*	**11.13**	9.03	23	**9.62**	8.13	18

Per share amounts

The following table summarizes the common shares used in calculating funds from operations and net earnings per common shares.

	Three months ended December 31		Twelve months ended December 31	
(Weighted average common shares)	**2003**	2002	**2003**	2002
Basic	**48,092,297**	44,765,776	**45,715,200**	43,784,181
Diluted	**51,238,299**	45,562,746	**48,844,039**	44,942,014
End of year	**57,085,776**	44,765,776	**57,085,776**	44,765,776

Funds from operations

($'s)	Three months ended December 31 **2003**	2002	%	Twelve months ended December 31 **2003**	2002	%
Funds from operations	**1,916,311**	1,226,491	56	**7,256,342**	4,413,107	64
Funds from operations per share – basic	**0.04**	0.03	45	**0.16**	0.10	57
Funds from operations per share – diluted	**0.04**	0.03	39	**0.15**	0.10	51
Funds from operations per boe	**15.59**	15.50	1	**16.93**	14.44	17

Our funds from operations for the fourth quarter of 2003 increased by 56% to $1,916,311 compared to $1,226,491 for the fourth quarter of 2002. For the fourth quarter of 2003, our funds from operations averaged $15.59/boe, an increase of 1% from the $15.50/boe recorded in the fourth quarter of 2002.

Our funds from operations for 2003 increased 64% to $7,256,342 compared to $4,413,107 for 2002. Our basic funds from operations per share increased by 57% to $0.16 ($0.15 diluted) for 2003, while our basic funds from operations per share were $0.10 ($0.10 diluted) for the same period in 2002.

On a per boe basis, our funds from operations, improved by 18% during 2003 to $17.04/boe from $14.47/boe in 2002. Our funds from operations are defined as cash flow from operating activities, as calculated in our "Consolidated Statement of Cash Flows" before adjustments for changes in non-cash working capital, the components of which will be detailed in the notes to our consolidated financial statements for the year ended December 31, 2003.

Net earnings

Our net earnings for the fourth quarter of 2003 totaled $181,016 ($0.00 per share basic and diluted) compared to $267,233 ($0.01 per share basic and diluted) for the fourth quarter of 2002, a decrease of 32%. Earnings before extraordinary items for the fourth quarter increased 25% to $181,016 from the $144,928 recorded in the fourth quarter of 2002.

Our net earnings for 2003 increased 87% to $2,221,229 ($0.05 per share basic and diluted) from net earnings before extraordinary items of $1,187,363 ($0.03 per share basic and diluted) in 2002.

($'s unless noted)	Three months ended December 31 **2003**	2002	%	Twelve months ended December 31 **2003**	2002	%
Net earnings, before extraordinary item	**181,016**	144,928	25	**2,221,229**	1,187,363	87
Net earnings	**181,016**	267,233	(32)	**2,221,229**	1,309,668	70
Earnings per share – basic	**0.00**	0.01	(37)	**0.05**	0.03	66
Earnings per share – diluted	**0.00**	0.01	(39)	**0.05**	0.03	59
Earnings per boe	**1.44**	3.35	(57)	**5.18**	4.29	21
Return on average equity (%) annualized (1)	**4.2**	6.8	(38)	**13.7**	16.8	(18)

(1) before extraordinary item

After giving effect to the financing we completed on December 10, 2003, our weighted average return on equity for 2003 was 13.7%, down from the 16.8% in 2002. For comparative purposes, the weighted average return on equity for 2003, excluding the equity financing we undertook, would have been 22.5% (6.6% in the fourth quarter of 2003). Due to the timing of our equity issue, the financing had only a limited effect on our financial results of 2003.

Ceiling test

The ceiling test is a cost recovery test and is not intended as an estimate of fair market value. The test compares the value of proven reserves, calculated using average period-end prices, to the book value of those reserves. In periods of rapid price fluctuations, however, average prices over a specified period may be used in the calculation. The test takes into consideration royalties, operating cost, interest, G&A expenses and taxes.

If the value of the future net revenues from proven reserves is determined to be less than the book value of the reserves, a write down of the book value of the reserves must be taken. As at December 31, 2003, we had a ceiling test cushion of $19.0 million (no impairment) in the carrying value of our property and equipment book values, using average period-end prices held constant throughout the life of the remaining reserves.

Capital expenditures

Our 2003 capital expenditure program was financed through a combination of new equity, existing credit lines, and cash flow generated from operations. Net capital expenditures totaled $23,385,548 for 2003. Capital expenditures during 2003 were focused on the continued development of the Stettler area natural gas prospect as well as the Sousa, Lousana and Mann Lake oil projects. Capital spending for the fourth quarter of 2003 was $13.2 million, of which a net $8.4 million was spent in the swap and/or acquisition of additional natural gas and light oil properties and the balance of $4.8 million was directed towards natural gas development in the central Alberta area. Additionally, during 2003, we spent $128,753 on site restoration costs.

	Three months ended December 31		Twelve months ended December 31	
($000's - unaudited)	**2003**	2002	**2003**	2002
Land and retention costs	**272**	100	**1,058**	136
Seismic	**57**	14	**584**	100
Acquisitions	**13,685**	30	**14,816**	525
Dispositions	**(5,234)**	(206)	**(5,385)**	(409)
Drilling and completions	**3,400**	536	**8,422**	895
Facility and equipment	**900**	184	**3,467**	1,210
Capitalized G&A	**127**	137	**381**	343
Administrative assets	**20**	44	**43**	74
Total capital expenditures	**13,227**	839	**23,386**	2,874

Liquidity and capital resources

At the end of 2003, we were in a net debt position of $7.9 million, consisting of $6.1 million in bank debt and a working capital deficiency of $1.8 million. Our net debt levels remain within our current target of an expected funds flow multiple of one to two times funds flow. At the end of 2002, we had net debt of $4.0 million.

As at December 31, 2003, we had a $12.0 million revolving operating demand loan facility and a $10.0 million non-revolving acquisition and development demand loan facility. At December 31, 2003, we had drawn a total of $6.1 million on these loan facilities. Subsequent to December 31, 2003, we secured a new lending facility, with our bankers providing for a $18.0 million revolving operating demand loan facility.

We believe that we have the capital resources in hand to carry out our currently planned 2004 capital expenditure program without the need for new equity, given our current unused debt capacity and our expected cash flow for 2004. Significant changes in our planned 2004 capital expenditure program or a significant acquisition could necessitate additional equity.

A summary of our existing contractual obligations at year end 2003 is set out below.

Contractual obligations

		Payments due by period			
($000's)	**Total**	1 year or less	1 – 3 years	4 – 5 years	After 5 years
Bank debt [1]	**6,100**	–	–	–	–
Operating lease	**262**	189	73	–	–
Office lease	**618**	248	370	–	–
Total contractual obligations	**6,980**	437	443	–	–

(1) Bank debt is a revolving operating demand loan subject to an annual borrowing base review that does not currently call for any repayments or availability reductions.

Equity

On December 10, 2003, we completed a bought deal financing pursuant to which we issued 11,820,000 common shares at $1.10 per common share for gross proceeds of $13,002,000. Additionally, during 2003, we issued 500,000 common shares pursuant to the exercise of stock options for gross proceeds of $100,000.

As of the date hereof, we have 57,085,776 common shares and 4,225,000 stock options outstanding. A maximum number of 4,225,000 common shares are issuable upon the exercise of all outstanding stock options.

Capital requirements

We will continue to finance our activities through future equity offerings, internally generated cash flow and existing bank credit lines. We intend to use these sources of funding to pursue expansion in existing project areas. It is possible that the various sources of financing currently available to us may not be available when required, or may not be attainable in the amounts or on terms acceptable to us when required to finance our ongoing activities.

Net asset value

As at December 31, 2003, our net asset value, using total proven plus probable reserves was $0.68 per share basic ($0.66 per share diluted), a 106% increase from the December 31, 2002 net asset value of $0.33 per share basic ($0.32 per share diluted).

The following table summarizes our net asset value calculation.

($000's)	**2003**	2002	%
Reserves discounted at 10% pre-tax [1] *($)*	**44,873**	17,564	155
Undeveloped land [2] *($)*	**2,134**	1,303	64
Working capital deficit *($)*	**(1,847)**	(347)	432
Bank Debt *($)*	**(6,100)**	(3,650)	67
Net asset value – basic *($)*	**39,060**	14,870	163
Proceeds of stock options	**1,322**	968	37
Net asset value – diluted *($)*	**40,382**	15,838	155
Common shares outstanding, year-end	**57,086**	44,766	28
Diluted common shares *(000's)* [3]	**61,311**	48,976	25
Per share amounts			
Basic	**0.68**	0.33	106
Diluted	**0.66**	0.32	106

(1) Established reserves for 2002; total proven plus probable reserves for 2003. See reserves summary section for discussion.

(2) Undeveloped land is evaluated on a property specific basis.

(3) Diluted shares includes shares outstanding plus outstanding options at December 31, 2003.

Business risks

As a junior petroleum and natural gas explorer, developer and producer, we are faced with various risks inherent to the oil and gas industry that are outside of our control. These include: exploration uncertainty, production risk, access to processing and shipping facilities, commodity price fluctuation, interest and foreign exchange rate risks, conditions affecting the supply and demand for hydrocarbons, government regulations, royalty and tax structures, and environmental protection.

The oil and gas industry in western Canada is highly competitive and we compete with other oil and gas companies that have greater resources. Our continued success will depend upon our ability to find new hydrocarbon reserves at a low cost through exploration, development and acquisition and in conducting our operations in a cost-effective manner.

We attempt to mitigate the various forms of risk inherent in the industry in a number of ways, including: employing experienced and motivated staff, utilizing new technologies, controlling and reviewing ongoing costs, generating new economic projects in areas where we have a good understanding of the geological risks and potential, diversification of commodity mix, use of financial hedging instruments, and maintaining sufficient levels of business, comprehensive and property insurance to safeguard our assets

Environment and safety

The oil and gas industry is subject to environmental regulation under federal and provincial legislation. Some of our operations are in environmentally sensitive areas. We are committed to conducting our operations in a manner that minimizes environmental impact and the likelihood of environmental damage. Environmental reviews are completed as part of our due diligence when new property acquisitions are made. Additionally, we have implemented a program to review all of our producing properties on a rotating basis to assess and monitor the environmental impact of our operations We estimate and provide for our liability in respect of the reclamation and restoration of lands upon which our operations are conducted.

We maintain a safety policy that is designed to comply with current government regulations for the oil and gas industry. Our employees and field contractors receive necessary training, follow our safety manual and the policies set out in occupational health and safety regulations. We monitor these standards to ensure compliance with any change to the policies or regulations. Regular safety audits are undertaken to ensure that all operations comply with government regulations and industry standards and to identify opportunities to reduce the risks associated with field operations. We also maintain a formal emergency response plan detailing procedures that our employees and contractors must follow in the event of an emergency.

2004 Activity update and outlook

Crispin has finished its winter program in the Stettler project area. The program saw a total of 11 gross (8.7 net) wells drilled with targets at a depth of 1,000 - 1,800 meters. The program spending was split approximately 70% to shallow gas targets and 30% on deeper Cretaceous zones. This program should yield 300 - 400 boe/d of on stream rate net to Crispin by early Q2. The Stettler area continues to yield consistent rate and reserve results and, accordingly, Crispin will undertake a Q2 and Q3 drilling program of 6 - 10 gross wells on both the recently acquired Mikwan properties and the Three Hills project.

Crispin's Q4, 2003 production averaged 1,366 boe/d while company production is 1,500 boe/d prior to the tie-in of the Q1 program. The Company did experience a 110 boe/d volume reduction resulting from operational difficulties with a Keg River well during Q1. The Company has elected not to pursue an operationally aggressive approach to production recovery at this time due to seasonal access limitations at Sousa.

Crispin is projecting a 2004 average annual production rate of 1,750 - 1,825 boe/d, which represents 50-55% growth on an annualized basis. The financial outlook for the Company continues to be strong. Crispin projects 2004 cash flow between $11.5 - $12.5 million and year-end debt to cash flow ratio between 0.6 - 0.9 depending on commodity pricing. This balance sheet strength allows Crispin to continue focusing on the patient pursuit of assets with upside potential that fit the corporate strategy. Crispin has increased its capital budget by $4.0 million to $15.2 million to accommodate expanded Q2 and Q3 drilling in 2004, and to increase the land and seismic budget allocation.

Financial Reporting and Regulatory Update

Several changes have taken place in the financial reporting and securities regulatory environments in 2003 that will impact us, and all public companies, during 2003 and 2004. The Canadian securities regulators and the Canadian Institute of Chartered Accountants ("CICA") are undertaking these measures to increase investor confidence through increased transparency, consistency and comparability of financial statements and financial information. These changes have also been brought about by the goal of harmonizing Canadian standards more closely with those in the United States.

In 2003, we implemented the new accounting standard set out below, which had the following impact on our 2003 consolidated financial statements:

Stock based compensation and other stock based payments

During September 2003, CICA issued an amendment to section 3870 "Stock based compensation and other stock based payments." The amended section is effective for fiscal years beginning on or after January 1, 2004; however, earlier adoption is recommended. The amendment requires companies to measure all stock based payments using the fair value method of accounting and to recognize the compensation expense in their financial statements. We have implemented this amended standard in 2003 in accordance with the early adoption recommendation. According to the transitional provisions, early adoption requires that the compensation expense be calculated and recorded in the income statement for stock options issued on or after January 1, 2003. As a result of implementing this amended standard, our net income decreased by $105,913 due to the estimated compensation expense on employee stock options issued on or after January 1, 2003.

In 2004, we will implement the new standards set out below, which will have the following impact on our 2004 consolidated financial statements:

Full cost accounting guideline

In September 2003, CICA issued Accounting Guideline 16 entitled "Oil and Gas Accounting - Full Cost" to replace CICA Accounting Guideline 5. CICA Accounting Guideline 16 proposes amendments to the ceiling test calculation we apply, and is effective for fiscal years beginning on or after January 1, 2004. Implementing CICA Accounting Guideline 16 will not have a material impact on our financial results for 2004.

Asset retirement obligations

CICA issued Section 3110 that harmonizes Canadian GAAP with Financial Accounting Standards Board statement No.143 entitled "Accounting for Asset Retirement Obligations". The new standard requires that companies recognize the liability associated with future site reclamation costs in their financial statements at the time the liability is incurred. The new Canadian standard is effective for fiscal years beginning on or after January 1, 2004. We do not expect the implementation of this new guideline to materially impact our financial results for 2004.

Corporate Governance

In 1995, The Toronto Stock Exchange (the "TSX"), through its Committee on Corporate Governance, established certain guidelines for corporations to follow to effect appropriate corporate governance. The TSX revised its guidelines relating to corporate governance, which apply to all TSX listed companies whose fiscal year ended on or after December 31, 1999 and is applicable to certain TSX Venture Exchange companies effective December 31, 2002.

The Corporation has established policies and procedures adopting certain of the guidelines which the Board of Directors (the "Board") have determined are important to meet corporate objectives and direction while at the same time providing for the best interests of the Corporation and its shareholders. Listed below are the 14 guidelines proposed by the TSE Report and a brief discussion of the Corporation's compliance with the guidelines.

The Board should explicitly assume responsibility for stewardship of the Corporation, and specifically for adoption of a strategic planning process, identification of principal risks, succession planning and monitoring, communications policy and integrity of internal control and management information systems.

The Board of Directors acknowledges its responsibility for the stewardship of the Corporation in overseeing the business and affairs of the Corporation. In particular, the Board:

- ensures the Corporation has appropriate short and long-term goals and has implemented a strategic planning process, which takes into account, among other things, the opportunities and risks of the business.
- identifies the principal business risks and ensures proper systems are in place to manage these risks and protect shareholder value.
- ensures that senior management is of the highest calibre and that adequate systems are in place for the appointment, development and monitoring of senior management to facilitate the orderly succession of senior management.
- ensures the Corporation's communication policy enables it to effectively communicate with shareholders, other stakeholders and the public generally, including the capital markets.
- ensures the Corporation has in place adequate internal controls and management information systems.

2) A Majority of directors should be "unrelated" (free from conflicting interest).

The Board of Directors is comprised of 5 members, all of whom have extensive and varied business experience. The majority of the directors are "unrelated directors", as defined in the Report of The Toronto Stock Exchange Committee on Corporate Governance in Canada. The Corporation does not have a significant shareholder with the ability to exercise a majority of the votes for the election of directors.

Disclose for each director whether he or she is related, and how that conclusion was reached.

All of the members of the Board of Directors of the Corporation are non-management "unrelated directors" with the exception of Mr. Murray Nunns, President and CEO and Mr. William Bradley, Executive Vice President.

4) Appointment of a Committee responsible for appointment/assessment of directors

The Board as a whole reviews any proposed new nominee for the Board.

5) Implement a process for assessing the effectiveness of the Board, its Committees and individual directors.

Responsibility for the assessment of the effectiveness of the Board as a whole, the committees of the Board and the contribution of individual directors remains with the full Board and are dealt with through the actions of the entire Board.

6) Provide orientation and education programs for new directors

The Corporation provides orientation to new directors on an informal basis upon them being invited to join the Board of Directors based upon the director's background and knowledge of our business and operations.

7) Consider reducing size of Board, with a view to improving effectiveness

The Corporation's Articles of Association restrict the size of the Board to a maximum of 7 members. The current size of the Board is 5 directors. With the Corporation's growth and its plans for the future, the Corporation believes that the size of the Board may need to be increased in order to fulfill the Board's mandate and those of its committees and to facilitate effective decision-making.

8) Review the compensation of directors in light of risks and responsibilities

The Board created the Compensation Committee comprised of "unrelated directors" who are:

- Glen Phillips
- Robert Eldridge

One of its key functions is to review the adequacy and form of directors' compensation and make recommendations designed to ensure the directors' compensation realistically reflects the responsibilities of the Board of Directors. It is also responsible for the overall approval of the Corporation's compensation policies and levels of compensation.

9) Committees should generally be composed of outside directors, a majority of whom are unrelated

The Board has established three committees:

(i) the Compensation Committee as described in paragraph 8;

(ii) the Audit Committee as described in paragraph 13; and,

(iii) the Reserve Committee comprised of a majority of non-management "unrelated directors" who are:

- Glen Phillips
- John Burns
- Murray Nunns

The Reserve Committee communicates directly with the Corporation's external independent engineering firm to review the qualifications of and procedures used by the independent engineers in determining the estimate of the Corporation's quantities and value of petroleum and natural gas reserves remaining.

10) Appoint a Committee responsible for approach to corporate governance issues..

The Board as a whole assumes the responsibility for developing the Corporation's approach to governance issues and is responsible for the Corporation's response to these governance guidelines.

11) The Board should develop position descriptions for the Board and for the Chief Executive Officer, and the Board should approve or develop corporate objectives, which the Chief Executive Officer is responsible for meeting.

The President and CEO is accountable to the Board for meeting corporate objectives. The Board has delegated to the President and CEO the responsibility for the day-to-day management of our business subject to compliance with plans and objectives approved from time to time by the Board. Any responsibility that is not delegated to the President and CEO or a Board committee remains with the full Board. The Board approves all plans and corporate objectives.

12) Establish procedures to enable the Board to function independently of management.

The Board of Directors has functioned and is of the view that it can continue to function independently of management. The chairman is not a member of management, and is an "outside" and "unrelated" director. The Board and any committee of the Board can meet without management present whenever appropriate or deemed necessary.

13) Establish an Audit Committee with a specifically defined mandate (all members should be non-management directors).

The Board created the Audit Committee, which meets all statutory requirements and is comprised of:

- Robert Eldridge
- John Burns
- Glen Phillips

Who are all non-management "unrelated directors". The Board has determined that all members of the Committee are financially literate and at least one member has accounting or related financial expertise. The Audit Committee communicates directly with the Corporation's external auditors both with management and independent of management and is responsible for monitoring the preparation and audit of the Corporation's financial statements and the establishment of appropriate internal controls. The Audit Committee and the Board has adopted "Terms of Reference" which outlines the purpose of the Committee, its composition, procedures, and organization; and, its role and responsibilities.

14) Implement a system to enable individual directors to engage outside advisors, at Corporation's expense.

The full Board or any member of the Board can engage outside advisors at the expense of the Corporation in appropriate circumstances.

Board/Management roles and relationship

Management is responsible for the development of overall strategy and the preparation and implementation of related business plans. The role of the Board is to review and ultimately approve the long-term strategies and plans for Crispin. The Board relies significantly on the information and analysis provided by management. It has confidence in management's skills and administrative abilities.

The Board considers certain decisions are of sufficient importance that management will seek prior approval of the Board, such as:

- the approval of the annual capital and operating budget and any material changes to this budget;
- entering into forward pricing arrangements beyond 50% of current production volumes;
- the acquisition or sale of significant oil and natural gas assets in excess of pre-established guidelines;
- entering fixed interest rate or fixed exchange rate arrangements;
- all new debt or equity financing;
- changes to management group;
- all matters as required under the Business Corporations Act (Alberta); and
- significant changes in corporate policies, goals or objectives.

The Board meets on a regular quarterly basis and otherwise as required.

Insider trading guidelines

The Company has implemented insider trading guidelines which state that there will be an automatic trading black out for all employees, directors and contract staff for a period of fourteen (14) calendar days prior to and five (5) calendar days after the release of quarterly and financial statements. Additionally, trading blackouts for employees, directors and consultants will be put in place at the discretion of the directors or senior management as required when material issues, activities or transactions warrant.

2003 Financial Statements

Management's Report to the Shareholders

The accompanying consolidated financial statements and all information in the Annual Report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies in the notes to financial statements. When necessary, management has made informed judgments and estimates in accounting for transactions which were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared within acceptable limits of materiality, and are in accordance with Canadian generally accepted accounting principles (GAAP) appropriate in the circumstances. The financial information elsewhere in the Annual Report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management has prepared Management's Discussion and Analysis (MD&A). The MD&A is based upon the Company's financial results prepared in accordance with Canadian GAAP. The MD&A compares the audited financial results for the twelve months ended December 31, 2003 to December 31, 2002.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are properly authorized, assets are safeguarded and financial records properly maintained to provide reliable information for the preparation of financial statements.

KPMG LLP, an independent firm of Chartered Accountants, was engaged, as approved by a vote of shareholders at the Corporation's most recent annual general and special meeting, to audit the consolidated financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion.

The Audit Committee of the Board of Directors, which is comprised of three directors who are not employees of the Corporation, has discussed the consolidated financial statements, including the notes thereto, with management and external auditors. The consolidated financial statements have been approved by the Board of Directors on the recommendations of the Audit Committee.

President and
Chief Executive Officer

Vice-President Finance
and Chief Financial Officer

March 8, 2004

Auditors' Report to the Shareholders

We have audited the consolidated balance sheets of Crispin Energy Inc. as at December 31, 2003 and 2002 and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

CHARTERED ACCOUNTANTS
Calgary, Canada

March 8, 2004

Consolidated Balance Sheets

as at December 31

		2003	2002
ASSETS			
Current assets			
Cash		$ 36,087	$ –
Accounts receivable		2,345,822	1,608,857
Prepaids and deposits		245,964	106,689
		2,627,873	1,715,546
Property and equipment *(note 3)*		33,293,727	13,787,320
		$ 35,921,600	$ 15,502,866
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Bank overdraft		$ –	$ 405,667
Accounts payable and accrued liabilities		4,475,313	1,657,333
Bank debt *(note 4)*		6,100,000	3,650,000
		10,575,313	5,713,000
Future site restoration and abandonment		346,088	229,267
Future income taxes *(note 5)*		1,375,843	893,891
Shareholders' equity			
Share capital *(note 6)*		17,682,644	5,052,138
Contributed surplus *(note 6)*		105,913	–
Retained earnings		5,835,799	3,614,570
		23,624,356	8,666,708
Commitments *(note 9)*			
		$ 35,921,600	$ 15,502,866

tes to consolidated financial statements

On behalf of the Board of Directors

MURRAY R. NUNNS
Director

ROBERT H. ELDRIDGE
Chairman

Consolidated Statements of Earnings and Retained Earnings

Years ended December 31

		2003		2002
Revenue				
Petroleum and natural gas sales	$	14,858,035	$	9,890,913
Royalties, net of Alberta Royalty Tax Credit		(3,206,160)		(1,938,968)
Other		33,382		53,043
		11,685,257		8,004,988
Expenses				
Operating		2,909,473		2,402,850
General and administrative		1,106,314		821,437
Interest		345,597		299,371
Business development		19,100		59,223
Depletion, depreciation and amortization		4,124,724		2,483,495
Stock-based compensation *(note 6)*		105,913		–
		8,611,121		6,066,376
Earnings before taxes and extraordinary gain		3,074,136		1,938,612
Taxes *(note 5)*				
Capital tax		48,430		9,000
Future income taxes		804,477		742,249
		852,907		751,249
Earnings before extraordinary gain		2,221,229		1,187,363
Extraordinary gain *(note 2)*		–		122,305
Net earnings		2,221,229		1,309,668
Retained earnings, beginning of year		3,614,570		2,304,902
Retained earnings, end of year	$	5,835,799	$	3,614,570
Basic and diluted earnings per share *(note 6)*				
Before extraordinary gain	$	0.05	$	0.03
Net earnings	$	0.05	$	0.03

See accompanying notes to consolidated financial statements

Consolidated Statements of Cash Flows

Years ended December 31

	2003	2002
Cash flow provided by (used for):		
Operating activities		
Net earnings	$ 2,221,229	$ 1,309,668
Items not involving cash:		
Depletion, depreciation and amortization	4,124,724	2,483,495
Future income taxes	804,477	742,249
Stock-based compensation	105,913	–
Extraordinary gain	–	(122,305)
Funds from operations	7,256,343	4,413,107
Site restoration expenditures	(128,753)	–
Change in non-cash working capital *(note 7)*	(731,653)	(485,368)
Cash flow from operating activities	6,395,937	3,927,739
Advances (repayments) of bank debt	2,450,000	(2,050,000)
Issuance of common shares	13,102,000	703,250
Share issue costs	(794,019)	(11,587)
Cash flow from financing activities	14,757,981	(1,358,337)
Investing activities		
Additions to petroleum and natural gas properties	(28,770,233)	(3,283,750)
Proceeds on disposition of petroleum and natural gas properties	5,384,676	409,355
Change in non-cash working capital *(note 7)*	2,673,393	239,701
Cash flow from investing activities	(20,712,164)	(2,634,694)
Increase (decrease) in cash position	441,754	(65,292)
Cash (bank overdraft), beginning of year	(405,667)	(340,375)
Cash (bank overdraft), end of year	$ 36,087	$ (405,667)

l statements

Notes to Consolidated Financial Statements

Years ended December 31, 2003 and 2002

1. Significant accounting policies

(a) Nature of business

Crispin Energy Inc. (the "Company") is engaged in the exploration, development and production of petroleum and natural gas in Western Canada.

(b) Principles of consolidation

The consolidated financial statements include the accounts of the Company its subsidiaries and partnership all of which are wholly owned.

(c) Joint operations

Substantially all of the Company's exploration, development and production activities are conducted jointly with others and accordingly, the Company only reflects its proportionate interest in such activities.

(d) Measurement uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas properties, plant and equipment and the provision for future site restoration and abandonment costs are based on estimates. The cost recovery ceiling test is based on estimates of proved reserves, production rates, commodity prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

(e) Petroleum and natural gas properties

The Company follows the full cost method of accounting for petroleum and natural gas operations, whereby all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges directly related to exploration and development activities.

The Company conducts a cost recovery ceiling test to ensure capitalized costs less accumulated depletion and depreciation, future income taxes and the accumulated provision for future site restoration costs do not exceed the estimated future net revenues plus the cost of unproved properties, net of impairments. The future net revenues are calculated based on proved reserves, using year-end prices and costs. Estimated future capital costs, recurring general and administrative expenses, future financing costs, future site restoration costs, and income taxes are deducted in determining future net revenues. Any amount carried on the balance sheet in excess of the ceiling test limit is charged to current operations as additional depletion.

Proceeds from the disposition of petroleum and natural gas properties are applied against capitalized costs except for dispositions that would change the rate of depletion and depreciation by 20% or more, in which case a gain or loss would be recorded.

(f) Depletion and depreciation

Capitalized costs, together with estimated future capital costs associated with proved reserves, are depleted and depreciated using the unit of production method based on estimated gross proved reserves of petroleum and natural gas as determined by independent petroleum engineers. For purposes of this calculation, reserves and production are converted to equivalent units of petroleum based on relative energy content of six thousand cubic feet of natural gas to one barrel of petroleum. Costs of significant unproved properties, net of impairments, are excluded from the depletion calculation. These properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to the costs subject to depletion.

Other equipment, which is comprised of office equipment, furniture and fixtures, are recorded at cost and depreciated over their useful lives on a declining balance basis at 30%.

(g) Future site restoration and abandonment costs

A provision for future site restoration and abandonment costs, including the removal of production facilities at the end of their useful lives, is provided for over the estimated life of the proved reserves using the unit of production method. Costs are estimated each year by management, in consultation with engineers, based upon current regulations and industry practices. The annual charge is recorded as additional depletion and depreciation. Actual costs incurred are charged against the accumulated liability.

(h) Derivative financial instruments

The Company uses derivative financial instruments from time to time to hedge its exposure to commodity price risk. The Company does not enter into derivative financial instruments for trading or speculative purposes.

The derivative financial instruments are initiated within the guidelines of the Company's risk management policy. This includes linking all derivatives contracts to specific firm commitments or forecasted transactions. The Company believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term and notional amount do not exceed the Company's firm commitment or forecasted transaction and the underlying basis of the instrument, commodity price, matches the Company's exposure.

The Company enters into hedges of its exposure to petroleum and natural gas commodity prices by entering into crude oil and natural gas swap contracts, options or collars, when it is deemed appropriate. These derivative contracts, accounted for as hedges, are not recognized on the balance sheet. Realized gains and losses on these contracts are recognized in petroleum and natural gas revenue and cash flows in the same period in which the revenues associated with the hedged transaction are recognized. Premiums paid or received are deferred and amortized to earnings over the term of the contract.

Gains and losses resulting from changes in the fair value of derivative contracts that do not qualify for hedge accounting are recognized in earnings when those changes occur.

(i) Flow-through shares

Flow-through shares are issued at a fixed price and the proceeds are used to fund qualifying exploration and development expenditures within a defined time period. The expenditures funded by flow-through arrangements are renounced to investors in accordance with tax legislation. Share capital is reduced, and future tax liability is increased by the total estimated future income tax cost of the renounced tax deductions at the time of the issue.

(j) Income taxes

The Company uses the asset and liability method of accounting for income taxes. Under the asset and liability method, future income tax assets and liabilities are recognized for the future income tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future income tax assets and liabilities of a change in income tax rates is recognized in income in the period that includes the date of enactment or substantive enactment.

(k) Per share amounts

Basic per share amounts are computed by dividing net earnings by the weighted average shares outstanding during the reporting period. Diluted per share amounts are computed similar to basic per share amounts except that the weighted average shares outstanding are increased to include additional shares from the assumed exercise of stock options, if dilutive. The number of additional shares is calculated by assuming that outstanding stock options were exercised and that the proceeds from such exercises were used to acquire shares of common stock at the average market price during the reporting period.

(l) Use of estimates

The preparation of the financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

(m) Revenue recognition

Revenues associated with sales of crude oil, natural gas and natural gas liquids are recorded when title passes to the Company. Revenues from properties in which the Company has an interest with other producers are recognized on the basis of the Company's net working interest.

Change in accounting policy

(n) Stock based compensation

The Company has elected to prospectively adopt amendments to CICA Handbook Section 3870, Stock-Based Compensation and Other Stock-Based Payments, pursuant to the transitional provisions contained therein.

Under this standard, the Company must account for compensation expense based on the fair value of options granted under its' stock option plan. Previously, the Company accounted for compensation expense for stock options based on the intrinsic value of the options at the grant date.

For options granted in 2002 and prior years, the Company has elected to continue accounting for the stock based compensation based on the intrinsic value at the grant date and, for options granted in 2002, to continue to disclose pro forma results as if the amended accounting standard had been adopted retrospectively. Accordingly, net income for 2002 and subsequent years remains unchanged with respect to options granted in 2002, with the pro forma results disclosed in Note 6.

As a result of adopting this amended standard, net income for the year ended December 31, 2003 decreased by $105,913 and contributed surplus increased by $105,913. See Note 6 for additional information regarding the nature of the plan and the associated stock based compensation expense.

Acquisition of Mulberry Management Ltd.

Effective November 6, 2002, the Company acquired all of the issued and outstanding shares of Mulberry Management Ltd. ("Mulberry"), a private company, which is involved in the exploration, development and production of petroleum and natural gas in Western Canada for a cash consideration of $41,100. The acquisition has been accounted for by the purchase method of accounting. The accounts include the results of Mulberry effective November 6, 2002.

The fair values of the net assets acquired were as follows:

Net assets acquired:	
Working capital (including cash of $300)	$ 1,100
Future income tax asset	162,305
	163,405
Extraordinary gain	(122,305)
Cash consideration	$ 41,100

3. Property and equipment

	2003	2002
Petroleum and natural gas properties	**$ 42,706,229**	$ 19,320,672
Less: Accumulated depletion and depreciation	**(9,412,502)**	(5,533,352)
	$ 33,293,727	$ 13,787,320

During the year ended December 31, 2003, the Company capitalized $380,968 (2002 - $343,315) of general and administrative costs directly related to exploration and development activities. As at December 31, 2003, the depletion and depreciation calculation excluded unproved properties of $3,184,600 (2001 - $884,046). At December 31, 2003, the Company has estimated the undiscounted future site restoration and abandonment costs to be accrued over the life of the remaining proved reserves to be $3,880,100 and equipment salvage is estimated at $1,728,300 (2001 - $530,100 net of salvage).

4. Bank debt

At December 31, 2003 the Company had a $12.0 million revolving operating demand loan facility and a $5.0 million non-revolving acquisition and development demand loan facility. Interest is payable on borrowings under the operating facility at an interest rate of Canadian prime plus one half of one percent and under the acquisition and development facility at an interest rate of Canadian prime plus three quarters of one percent. These credit facilities are subject to an annual borrowing base review, the next due May 31, 2004, and do not currently call for any repayments or availability reductions. Collateral for the credit facility consists of a general assignment of book debts, a $5 million debenture with a fixed and floating charge over certain of the Company's assets and a fixed and floating charge supplemental debenture in the amount of $25.0 million covering the primary petroleum and natural gas assets of the Company. As of December 31, 2003 the Company had drawn $6.10 million (2002 - $3.65 million) on its operating facility and $ nil on the acquisition and development facility. Subsequent to year end the Company renewed its' banking facilities and has now secured a $18.0 million revolving operating demand loan facility.

5. Income taxes

Income taxes recorded on the statement of operations and retained earnings differ from the tax calculated by applying the combined federal and provincial income tax rate to income before taxes as follows:

	2003	002
Corporate income tax rate	**40.62%**	42.12%
Estimated income tax expense	**$ 1,248,725**	$ 816,543
Increase (decrease) in income taxes		
Non-deductible crown charges, net of ARTC	**444,181**	354,096
Non-deductible stock based compensation	**43,022**	–
Federal resource allowance	**(706,103)**	(397,338)
Tax rate reduction	**(225,348)**	(31,052)
Future income taxes	**804,477**	742,249
Capital tax	**48,430**	9,000
Provision for taxes	**$ 852,907**	$ 751,249

The components of future income tax liability consist of the following temporary differences:

	2003	2002
Property and equipment	**(1,862,058)**	(1,022,840)
Site restoration	**119,816**	72,425
Capital losses	**104,495**	108,354
Non-capital losses	**3,656**	3,791
Share issue expense	**326,534**	15,075
Other	**36,209**	37,658
	(1,271,348)	(785,537)
Less: valuation allowance	**(104,495)**	(108,354)
Future income tax liability	**(1,375,843)**	(893,891)

6. Share capital

(a) Authorized

Unlimited number of common shares

150,000 preferred shares

(b) Issued Common shares

	Number of shares	Amounts
Balance at December 31, 2001	42,186,231	$ 4,569,811
Shares issued for cash	750,000	150,000
Shares issued on exercise of stock options	275,000	56,250
Flow through shares issued for cash, net of future taxes of $209,337	1,554,545	287,663
Share issue costs, net of income taxes	–	(11,586)
Balance at December 31, 2002	44,765,776	$ 5,052,138
Shares issued on exercise of stock options	500,000	100,000
Shares issued for cash	11,820,000	13,002,000
Share issue costs, net of income taxes	–	(471,494)
Balance at December 31, 2003	**57,085,776**	**$ 17,682,644**

On February 7, 2002, the Company provided a loan to an officer of the Company to acquire 750,000 common shares at $0.20 per share and 200,000 flow-through common shares at $0.25 per share for aggregate consideration of $200,000. The loan was repaid prior to December 31, 2002.

(c) Flow-through share agreements

During 2002, the Company entered into flow-through share agreements, whereby the Company agreed to issue 1,554,545 flow-through common shares, in consideration for renouncing $497,000 in qualifying expenditures prior to December 31, 2002. As of December 31, 2003 the Company had satisfied its obligation under the flow-through agreement.

(d) Stock options

The Company has established a stock option plan whereby officers, directors and employees may be granted options to purchase common shares. A maximum of 10% of the outstanding common shares of the Company may, from time to time be allocated for issuance to eligible participants. Under this program, the exercise price of each option equals the market price of the Company's stock on the date of grant, the options maximum term is five years, with various vesting periods.

The following table summarizes the changes in the stock option plan.

	2003		2002	
	Number of Shares	**Weighted average price**	Number of Shares	Weighted average price
Balance, January 1	**4,210,000**	**$ 0.23**	2,610,000	$ 0.20
Exercised	**(500,000)**	**0.20**	(275,000)	0.20
Granted	**515,000**	**0.87**	1,875,000	0.27
Balance, December 31	**4,225,000**	**$ 0.31**	4,210,000	$ 0.23
Exercisable at December 31	**2,961,000**	**$ 0.24**	2,670,000	$ 0.22

At December 31, 2003 the options outstanding had exercise prices ranging from $0.15 to $1.00 with a weighted average contractual life of 2.8 years.

(e) Per share amounts

The following table summarizes the common shares used in calculating earnings per share.

Weighted Average Common Shares	2003	2002
Basic	**45,715,200**	43,784,181
Diluted	**48,844,039**	44,942,014

The reconciling items between the basic and diluted common shares result from in the the money stock options.

(f) Stock based compensation

The Company has recorded stock based compensation expense and contributed surplus in the amount of $105,913 for stock options issued on or after January 1, 2003. For stock options granted in 2002, the Company has elected to continue to disclose pro forma results as if the amended accounting standard had been applied retroactively. The Company's pro forma earnings for the years ended December 31, 2003 and December 31, 2002 are disclosed below. Basic and diluted earnings before extraordinary gain per share and net earnings per share remain unchanged.

Compensation costs	2003	2002
Net Earnings:		
As reported	**$ 2,221,229**	$ 1,309,668
Pro forma	**1,925,428**	1,141,620

The fair value of each option granted is estimated on the date of grant using the Modified Black-Scholes option-pricing model with the following assumptions.

Assumptions	2003	2002
Weighted average grant date fair value *($)*	**$ 0.57**	$ 0.26
Average risk-free interest rate *(%)*	**5.0**	5.0
Average volatility *(%)*	**77**	163
Average expected life	**Five years**	Five years

7. Supplemental cash flow information

Changes in non-cash working capital	2003	2002
(Increase) decrease in accounts receivable	**$ (736,965)**	$ (439,287)
(Increase) decrease in prepaids and deposits	**43,193**	(27,183)
(Increase) decrease in inventory	**(182,468)**	–
Increase (decrease) in accounts payable	**2,817,980**	220,803
Change in non-cash working capital	**$ 1,941,740**	$ (245,667)
Relating to:		
Investing activities	**2,673,393**	239,701
Operating activities	**(731,653)**	(485,368)
Change in non-cash working capital	**$ 1,941,740**	$ (245,667)
Cash interest paid	**$ 345,597**	$ 299,371
Cash taxes paid	**9,000**	–

8. Risk management

(a) Fair value of financial instruments

At December 31, 2003, the fair value of cash, accounts receivable, deposits, bank overdraft, accounts payable and accrued liabilities approximate their carrying value due to their current maturities. The bank debt carrying value approximates fair value due to the cost of borrowing being at a floating rate.

(b) Commodity price risk

The Company is party to certain derivative financial instruments that have fixed the price of a portion of its crude oil production. For the year ended December 31, 2003, the Company realized a reduction of $397,345 (2002 - $109,973) of revenues on its commodity hedging program.

Contracts outstanding in respect to price risk management at December 31, 2003 were as follows;

Contract	Volume	Strike price	Term
Crude Oil			
Costless collar [1]	400 bbls/d	US $25.00 - US $32.50	January 1, 2004 - March 31, 2004
Costless collar [1]	400 bbls/d	US $26.00 - US $32.00	April 1, 2004 - June 30, 2004
Natural Gas			
Costless collar [1] [2]	1,000 GJ/d	CA $5.00 - CA $ 7.00	April 1, 2004 - October 31, 2004
Costless collar [1] [2]	1,000 GJ/d	CA $5.00 - CA $6.75	April 1, 2004 - October 31, 2004

(1) Costless collar strike price indicates floor and ceiling pricing.

(2) Contract executed January 2004.

The estimated fair value of the open contracts at December 31, 2003, had they been settled at that time would have resulted in a payment of $87,624. These instruments have no carrying amount recorded in the financial statements.

(c) Credit risk

The Company is subject to credit risk through trade receivables. Although a substantial portion of its debtor's ability to pay is dependent upon the oil and gas industry, credit risk is considered minimal. Management routinely assesses the financial strength of partners and customers including parties involved in marketing or commodity arrangements. The Company is exposed to credit risk associated with possible non-performance by derivative instrument counter parties. The Company does not require collateral, however, it does limit total exposure to individual counter parties.

(d) Interest rate risk

The Company's credit facilities are subject to floating interest rates. As such any debt carried on the books by the Company would be subject to interest rate cash flow risk, as the required cash flow to service debt would fluctuate as a result of changes in market rates. The Company had total borrowings outstanding under its available credit facilities as of December 31, 2003 of $ 6,100,000 (2001 - $3,650,000).

9. Commitments

(a) Office lease

During 2002 the Company entered into a sub-lease agreement for new office premises expiring in May 2006. Annual lease payments for these office premises including estimated operating costs are as follows:

2004	$ 248,293
2005	$ 261,193
2006	$ 108,830

(b) Operating lease

Additionally, in return for third party construction of additional gas gathering and processing facilities, the Company has committed to a minimum annual processing and gathering fee of $188,700, until payout of these facilities is reached in May 2005.

Five-Year Review

For the years ended December 31

($000's except where noted)	2003	2002	2001	2000	1999
FINANCIAL STATISTICS					
Petroleum and natural gas sales	**14,858**	9,891	6,053	4,075	1,925
Royalties	**(3,210)**	(1,953)	(1,256)	(771)	(488)
ARTC	**4**	14	20	26	31
Operating expenses	**(2,909)**	(2,403)	(1,675)	(1,041)	(438)
Operating netback	**8,743**	5,549	3,142	2,289	1,030
General and administrative	**(1,106)**	(821)	(417)	(291)	(362)
Interest and taxes	**(394)**	(309)	(202)	(72)	(82)
Other expenses	**(19)**	(59)	–	–	–
Other income	**33**	53	145	25	7
Funds from operations	**7,257**	4,413	2,668	1,951	593
Depletion, depreciation and amortization	**(4,125)**	(2,483)	(1,577)	(773)	(318)
Stock based compensation	**(106)**	–	–	–	–
Future income taxes	**(805)**	(742)	(397)	(539)	–
Extraordinary gain	**–**	122	–	–	–
Net income	**2,221**	1,310	694	639	275
Funds from operations (basic & diluted) *($/share)*	**0.16**	0.10	0.06	0.05	0.02
Earnings per share (basic & diluted) *($/share)*	**0.05**	0.03	0.02	0.02	0.01
Capital expenditures	**23,386**	2,874	7,608	3,248	2,250
Total book assets	**35,922**	15,503	14,582	8,491	6,046
Working capital deficiency	**1,847**	347	528	776	658
Bank debt	**6,100**	3,650	5,700	675	225
Shareholders' equity	**23,624**	8,667	6,875	6,018	4,067
Depletion, depreciation, future site *($/boe)*	**9.62**	8.13	6.84	4.91	3.64
Return on average equity	**13.7%**	16.3%	10.2%	20.9%	8.7%
Common shares *(thousands)*					
Basic weighted average outstanding	**45,715**	43,784	41,666	38,852	29,604
Basic shares outstanding *(year-end)*	**57,086**	44,766	42,186	41,366	38,566
Diluted weighted average outstanding	**48,844**	44,942	42,063	39,015	31,182

($000's, except where noted)	2003	2002	2001	2000	1999
MARKET INFORMATION					
High *($/share)*	**1.35**	0.89	0.39	0.34	0.25
Low *($/share)*	**0.63**	0.17	0.12	0.13	0.05
Close *($/share)*	**1.15**	0.75	0.23	0.16	0.21
Shares traded *(thousands)*	**9,398**	6,901	3,981	4,220	2,542
OPERATING STATISTICS					
Average sales prices					
Natural gas *($/mcf)*	**6.09**	3.64	4.49	4.08	2.59
Oil/NGL's *($bbl)*	**35.46**	34.31	26.85	26.85	23.02
Netbacks					
Field netback *($/boe)*	**21.32**	18.52	14.27	14.71	11.80
Funds from operations *($/boe)*	**16.93**	14.44	11.58	12.54	6.81
Daily production					
Natural gas *(mcf/d)*	**818**	640	496	270	156
Light oil/NGL's *(bbls/d)*	**775**	520	323	154	78
Heavy oil *(bbls/d)*	**263**	210	226	227	135
Average daily boe's @ 6:1	**1,175**	837	632	426	239
Annual production					
Natural gas *(mcf)*	**298,723**	233,451	181,195	98,726	56,867
Light oil and liquids *(bbls)*	**283,045**	190,003	117,683	56,041	28,607
Heavy oil *(bbls/d)*	**95,846**	76,703	82,658	83,022	49,173
Boe's @ 6:1	**428,678**	305,614	230,541	155,517	87,258
Employees	9	9	5	4	4

Quarterly Information

($000's, except per share amounts)	2002 Q1	2002 Q2	2002 Q3	2002 Q4	2003 Q1	2003 Q2	2003 Q3	2003 Q4
FINANCIAL *(unaudited)*								
Petroleum and natural gas sales [1]	2,049	2,340	2,782	2,721	**3,308**	**3,705**	**3,809**	**4,036**
Royalties	(396)	(466)	(467)	(610)	**(783)**	**(839)**	**(771)**	**(813)**
Operating expense	(555)	(533)	(699)	(617)	**(593)**	**(689)**	**(756)**	**(871)**
Field netback	1,098	1,341	1,616	1,494	**1,932**	**2,177**	**2,282**	**2,352**
Other income	1	25	10	16	**5**	**3**	**11**	**14**
General and administrative	(127)	(200)	(278)	(216)	**(292)**	**(293)**	**(206)**	**(315)**
Interest expense	(72)	(98)	(70)	(59)	**(53)**	**(77)**	**(123)**	**(93)**
Other expense	(29)	(31)	–	–	**(11)**	**(4)**	**(3)**	**(1)**
Capital tax	–	–	–	(9)	**(2)**	**(3)**	**(3)**	**(40)**
Funds from operations	871	1,037	1,278	1,226	**1,579**	**1,803**	**1,958**	**1,916**
Depreciation, depletion and amortization	(517)	(560)	(685)	(720)	**(733)**	**(922)**	**(1,073)**	**(1,396)**
Stock based compensation	–	–	–	–	**–**	**–**	**–**	**(106)**
Future income taxes	(70)	(127)	(183)	(361)	**(336)**	**(34)**	**(202)**	**(233)**
Extraordinary gain	–	–	–	122	**–**	**–**	**–**	**–**
Net income	284	348	410	267	**510**	**847**	**683**	**181**
Cash flow per share *(basic)*	0.020	0.024	0.029	0.028	**0.035**	**0.040**	**0.044**	**0.040**
Cash flow per share *(diluted)*	0.020	0.024	0.028	0.027	**0.034**	**0.038**	**0.041**	**0.037**
Earnings per share *(basic)*	0.007	0.008	0.009	0.007	**0.011**	**0.019**	**0.015**	**0.004**
Earnings per share *(diluted)*	0.007	0.008	0.009	0.006	**0.011**	**0.018**	**0.014**	**0.004**
PRODUCTION								
Oil and NGL's *(bbls/d)*	520	509	499	550	**635**	**842**	**789**	**833**
Heavy oil *(bbls/d)*	149	164	280	245	**225**	**268**	**302**	**254**
Total oil and NGL's	669	673	779	795	**860**	**1,110**	**1,091**	**1,087**
Natural gas *(mcf/d)*	842	791	502	429	**420**	**344**	**835**	**1,675**
Boe/d @ 6:1	809	805	863	866	**931**	**1,168**	**1,230**	**1,366**

(1) Net of hedging adjustments.

Corporate Information

BOARD OF DIRECTORS

ROBERT H. ELDRIDGE (1) (2)
Chairman, Crispin Energy Inc.
CFO, Northumbria Industries Ltd.
Toronto, Ontario

WILLIAM V. BRADLEY, P. ENG.
Executive Vice-President,
Crispin Energy Inc.
Calgary, Alberta

JOHN S. BURNS, Q.C. (1) (3)
Senior Partner, Bennett Jones LLP
Calgary, Alberta

MURRAY R. NUNNS, P. GEOL. (3)
President & Chief Executive Officer,
Crispin Energy Inc.
Calgary, Alberta

GLEN A. PHILLIPS, P. GEOL. (2) (3)
President, Eiger Energy Ltd.
Calgary, Alberta

(1) Audit Committee
(2) Compensation Committee
(3) Reserve Committee

OFFICERS AND KEY PERSONNEL

WILLIAM V. BRADLEY, P. ENG.
Executive Vice-President

GORDON CROOKS, P. GEOL.
Vice-President – Exploration

DARRIN FOSTER, P. ENG.
Vice-President – Production Operations

MURRAY D. GRAHAM, CGA
Vice-President, Chief Financial Officer & Corporate Secretary

PATRICK D. MANUEL, P. ENG.
Vice-President – Engineering & Business Development

MURRAY R. NUNNS, P. GEOL.
President & Chief Executive Officer

STOCK EXCHANGE

TSX VENTURE EXCHANGE
SYMBOL: "CEY"

TRANSFER AGENT

VALIANT TRUST COMPANY
510, 550 – 6th Ave. SW
Calgary, Alberta T2P 0S2

AUDITORS

KPMG LLP
Chartered Accountants
1200, 205 – 5th Ave. S.W.
Calgary, Alberta T2P 4B9

SOLICITORS

BENNETT JONES LLP
4500, 855 – 2nd St. S.W.
Calgary, Alberta T2P 4K7

BANKERS

NATIONAL BANK OF CANADA
600, 407 – 8th Ave. S.W.
Calgary, Alberta T2P 1E5

EVALUATION ENGINEERS

GILBERT LAUSTSEN JUNG ASSOCIATES LTD.
4100, 400 – 3rd Ave. S.W.
Calgary, Alberta T2P 4H2

ABBREVIATIONS

bbls	Barrels
bcf	Billions of cubic feet
boe	Barrels of oil equivalent
boe/d	Barrels of oil per day
mboe	Thousands of barrels of oil equivalent
mcf	Thousands of cubic feet
mcf/d	Thousands of cubic feet per day
mmboe	Millions of barrels of oil equivalent
mmcf	Millions of cubic feet
NGL's	Natural Gas Liquids
°API	Oil gravity in units of the American Petroleum Institute
ARTC	Alberta Royalty Tax Credit

Forward-Looking Statements

Statements throughout this annual report that are not historical facts may be considered "forward looking statements". These forward-looking statements sometimes include words to the effect that management believes or expects a stated condition or result. All estimates and statements that describe the Company's objectives, goals or future plans are forward looking statements. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to any number of factors, including such variables as new information regarding recoverable reserves, changes in demand and commodity prices for oil and gas, legislative, environmental and other regulatory or political changes, competition in areas were the Company operates and other factors discussed in this report.

CORPORATE OFFICES

1800, 407 – 2nd St. S.W.
Calgary, Alberta, Canada T2P 2Y3

Telephone: (403) 237-6375
Facsimile: (403) 265-5993

e-mail: info@crispinenergy.com
website: www.crispinenergy.com

Designed and produced by:
transcend Calgary + Seattle (403) 228-2248

Crispin

Energy Inc.